TABLE OF CONTENTS

I. INTRODUCTION

The Edwin I. Hatch Nuclear Plant-Unit 1 (HNP-1) safety-related system instrumentation upgrade program, which includes incorporation of the analog transmitter trip system (ATTS), comprises many equipment modifications and installations to meet many of the requirements and criteria of:

- IE Bulletin 79-01B, Environmental Qualification of Class 1E Equipment*
- NUREG-0737, TMI Lessons Learned*
- NUREG-0696, Safety Parameters Display System Interfaces*
- NUREG-0661, Low Low Set Trip Logic*.

This submittal covers information on ATTS (Section III) and the proposed plant design modifications (Section IV) being performed at Plant Hatch through the installation of ATTS during the 1984 refueling outage. This report will be updated for the 1985 refueling outage to include the remaining modifications being performed through the installation of ATTS.

The purpose of this submittal is to provide the bases for the proposed modifications and to provide Georgia Power Company's (GPC) proposed revisions to the Techiical Specifications.

ATTS and the associated plant modifications will be incorporated into the HNP-1 system logic prior to and during the next two refueling outages. The installation is scheduled to be completed by the startup of Cycle 10.

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*Subject shown is not necessarily title of document.

II. REFERENCES

1. Edwin I. Hatch Nuclear Plant Unit 2, Docket No. 50-366, Proposed Plant Modification-Low Low Set Logic and Lowered MSIV Water Level, GPC Letter NED-83-108, Proposal for Technical Specifications Changes Which Support Cycle 4 Startup, February 23, 1983.

2. IE Bulletin 79-01B, Environmental Qualification of Class 1E Equipment.

3. IEEE 323-74, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.

4. IEEE 344-75, IEEE Recommended Practices for Seismic Qualification of 1E Equipment for Nuclear Power Generating Stations.

5. NEDC-24346, Evaluation of Mark I S/RV Load Cases C3.2 and C3.3 for Edwin I. Hatch Nuclear Plant - Units 1 and 2.

6. NEDO-21617-A, General Electric Licensing Topical Report, Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Trip Inputs.

7. NUREG-0588, Revision 1, Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment.

8. NUREG-0661, Mark I Containment Long Term Program.

9. NUREG-0626, GE Evaluation of Feedwater Transients and Small Break LOCA in GE-Designed Operating Plants.

10. NUREG-0696, Functional Criteria for Emergency Response Facilities.

11. NUREG-0737, Clarification of TMI Action Plan Requirements.

12. Regulatory Guide 1.105, Instrument Setpoints.

13. Draft Standard Technical Specifications for General Electric Boiling Water Reactor (GE-STS) - BWR/4.

14. WASH-1400, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants.

15. Edwin I. Hatch Nuclear Plant Unit 2, Docket No. 50-366, Proposed Plant Modifications to be Incorporated Into ATTS Design, GPC Letter, NED-84-017, Request for Technical Specification Changes to Support Analog Transmitter Trip System Installation, January 23, 1984.

16. GPC Letter, NED-84-281, Response to NRC Staff Questions on Proposed ATTS Technical Specifications Changes, June 7, 1984.

17. GPC Letter, NED-84-321, Revised Responses to NRC Staff Questions on Proposed ATTS Technical Specifications Changes, June 14, 1984.

III. ANALOG TRANSMITTER TRIP SYSTEM (ATTS) INSTALLATION

A safety evaluation report was prepared to evaluate the licensing requirements of ATTS. From that evaluation, it was concluded that the incorporation of ATTS constitutes neither an unreviewed safety question, nor a significant hazards consideration. To keep the Nuclear Regulatory Commission (NRC) apprised of major Plant Hatch design modifications, Georgia Power Company (GPC) prepared a detailed description of the system to be installed. This detailed description provides all of the instrumentation to be incorporated into ATTS during the next two refueling outages. The general description of the proposed ATTS is provided in NEDE-22154-1 General Electric (GE) Licensing Topical Report (contained in Reference 15). NEDE-22154-1 is a plant-specific revision to the NEDO-21617-A document (Reference 6), which was approved by the NRC to use as a reference to license the ATTS design. NEDE-22154-1 contains the system/component design changes and additional qualification test data. Because no approved Arrhenius accelerated aging techniques were available when the original NEDO-21617-A document was issued, the equipment referencing the original NEDO-21617-A report is only partially qualified to IEEE 323-1974 requirements. To meet the IEEE 323-1974 and NUREG-0588 criteria, the ATTS to be installed at Plant Hatch-Unit 1 was requalified. A description of qualification testing is documented in Chapter 4 of NEDE-22154-1, and in addition identifies Plant Hatch testing criteria. Actual qualification reports will be provided to the NRC upon request.

Since the equipment comprising the ATTS was demonstrated to be superior to the mechanical switches currently used at Plant Hatch, certain technical specifications surveillance requirements may be revised. These revisions take advantage of the sensor improvements. Section III discusses the proposed surveillance revisions for the complete ATTS installation. The proposed plant modifications associated with ATTS and their justifications are discussed in Section IV.

3A. ATTS DETAILED DESIGN INFORMATION

3A.1 In NEDO-21617-A, dated December 1978, the NRC identified specific detailed information that each applicant (who uses that topical as a licensing basis) must provide relative to the specific application of the ATTS hardware into his plant. Since NEDE-22154-1 (contained in Reference 15) describes the same conceptual system as NEDO-21617-A but with different hardware, GPC is supplying the NRC with the same information (requested of those who use NEDO-21617-A as a licensing basis) regarding the Plant Hatch installation. Therefore, this section provides specific design criteria for the ATTS installation to be completed during the 1984 and 1985 refueling outages for Plant Hatch-Unit 1.

As identified in the NRC request section of NEDO-21617-A, GPC offers the information listed below.

3A.1.a The following information for each instrument loop that will be converted to the ATTS is provided in table 3.1:

- Variable name
- MPL number
- Engineered safeguards division
- Model number and vendor of the transmitter or RTD.
- Device's associated rack.

3A.1.b The layout of each card file in each trip unit cabinet, showing the trip variable for each card file slot, is provided in figures 3.1 through 3.8. These figures were developed to illustrate the 12 card slots per card file and the three card files per cabinet arrangement.

3A.1.c The environmental service conditions for Plant Hatch are presented in tables 4-1 through 4-3 of NEDE-22154-1. The seismic curves identified in these tables are the Unit 2 floor response spectra curves generated for the various mounting locations of the ATTS hardware. These Unit 2 curves envelop the corresponding Unit 1 curves and consequently may be used to define the seismic conditions for both units. Figures 3.9 through 3.21 correspond to or envelop the Plant Hatch safe shutdown earthquake curves. Table 4-5 and figures 4-5 through 4-12 of NEDE-22154-1 define the seismic levels to which the ATTS hardware was qualified. Comparison of the curves presented in figures 3.9 through 3.21 with the corresponding curves presented in figures 4-5 through 4-12 of NEDE-22154-1 shows that the ATTS hardware was seismically qualified to levels which exceed the Hatch requirements. Table 3.2 presents a summary of the various ATTS hardware along with the corresponding mounting locations and references to the applicable Plant Hatch seismic curves.

3A.1.d An interconnection diagram, showing the basic interconnections between the existing logic cabinets and the instrument cabinets and the new trip unit cabinets, is shown in figure 3.22. This interconnection diagram also presents the divisional separation of the cabinets.

3A.1.e The qualification program to the requirements of IEEE 323-74 and IEEE 344-75 was completed in December of 1983 with GE's issuance of the final qualification report (NEDC-30039). The details of the qualification program are presented in NEDE-22154-1. GPC will submit the final qualification reports (proprietary to GE) to the NRC upon request.

3.A.2 In a telecon with GPC, the NRC identified several questions regarding the Unit 2 ATTS licensing submittal. GPC's response to those questions was submitted to the NRC by GPC letters NED-84-281 dated June 7, 1984, and NED-84-321 dated June 14, 1984. GPC has also answered the same questions concerning ATTS design for Unit 1, below.

3.A.2.a QUESTION 1-1:

Please supply information relating to the power supply arrangement for the ATTS units within the RPS on both the primary and backup power systems. Also, please supply information with regard to the RPS and ECCS on how GPC ensures that an undervoltage condition could not exist which would incapacitate the trip functions for those systems.

RESPONSE:

The RPS portion of the ATTS is supplied, as is the remainder of the RPS, from the RPS MG set which has a class 1E undervoltage trip that initiates a scram on undervoltage. The system itself is a fail-safe system; therefore, with a loss of power, all instruments go to their safety positions. This arrangement is consistent with the original design bases of the plant.

The ECCS portion of the ATTS is powered off the plant batteries. The class 1E batteries are divisionalized and supplied by chargers that are powered off the emergency diesels. The batteries are sized per FSAR Section 8.5.3 for 2 hours continuous duty without the charger. The power supply for the ECCS portion of ATTS is consistent with the original design bases of the plant.

The installation of the ATTS system has not affected the design of the Plant Hatch ECCS and RPS power supplies. Undervoltage protection for the ECCS portion of the system is provided by the Class 1E batteries which are supplied by chargers that are powered from the emergency diesel generators. The RPS portion of the ATTS is protected by redundant Class 1E output breakers which will deenergize the RPS bus on an undervoltage condition. The minimum voltage that the batteries would ever show based on the FSAR requirement is 105 Vdc. The ATTS has voltage converters which work from 105 to 140 Vdc on the input-output to give a nominal output of 25 Vdc and a full-load voltage of 23.5 Vdc. The ATTS is designed to operate with a minimum voltage of 23.5 Vdc; therefore, the ATTS function is assured.

3.A.2 b QUESTION 1-2:

Does the MG set on the RPS also supply some non-Class 1E loads, and if so, what type of isolation devices separate the class 1E and non-Class 1E systems? Also, what type of surveillance is performed on those isolation devices?

RESPONSE:

The RPS MG sets supply a 120 V-ac power to the below listed loads. The design of these systems, including the additional hardware for the RPS portion of the ATTS is consistent with the design criteria established in the FSAR. It is also noted that all safety actuations associated with the listed systems, as well as the RPS portion of the ATTS goes to their safety position on a loss of RPS power. The additional hardware associated with the RPS portion of the ATTS is no more susceptible to failures than the hardware which it replaces. The systems powered from the RPS are as follows:

- RPS MG SET A

  Neutron Monitoring System
  Reactor Protection System
  Nuclear Steam Supply Shut Off System
  Primary Containment Isolation System
  Process Radiation Monitoring System

- RPS MG SET B

  Neutron Monitoring System
  Reactor Protection System
  Nuclear Steam Supply Shut Off System
  Primary Containment Isolation System
  Process Radiation Monitoring System
  Offgas Radiation Monitoring System

The ECCS dc distribution panels which supply essential dc power to the ECCS ATTS cabinets also supply some non-Class 1E loads. These distribution panels are supplied from the plant Class 1E batteries which are backed up by chargers fed by the emergency buses. Breakers are used to separate the non-Class 1E and the Class 1E systems. This is also consistent with the original design bases of the plant

The addition of ATTS into the plant design does not modify the original licensing bases of the plant with respect to the application of breakers in the RPS. The breakers used for undervoltage protection are Class 1E. Surveillance testing is required for these breakers per Unit 1 Technical Specifications Section 4.9.D.1. There is no commitment to perform surveillance testing on other breakers within the system. This is consistent with the original design basis of the plant in that Plant Hatch, Unit 1 is not required to meet Regulatory Guide 1.75.

3.A.2.c QUESTION 1-3:

Please provide the setpoints for the gross failure alarm.

RESPONSE:

The high/low gross failure setpoints are to be set at values of 35 $\pm$ 0.5 and 0.5 $\pm$ 0.5 mA., respectively. The alarms are provided to indicate a short-circuit and open-circuit. Therefore, the setpoint values can be varied significantly outside the saturation range of the transmitter and still provide adequate protection.

3.A.2.d QUESTION 1-4:

In the GE NEDO document topical report on ATTS, there is a table that talks about the maximum lead length that can be installed in the plant using the wire length and power supply voltage. What are we doing with regard to that table at Plant Hatch?

RESPONSE:

The table in question is presented in the Rosemount, Inc., "Operations Manual-Trip/Calibration System - Model 510DU," 1976. This manual is referenced in NEDO-21617-A. The Plant Hatch design, presented in NEDE-22154-1, does not use Rosemount trip units; GE trip units are used. However, the two trip unit designs are very similar.

The purpose of the maximum lead length requirement is to assure sufficient voltage out of the trip unit to drive the transmitter. Calculations by GE indicate that lead lengths as long as 3820 ft are acceptable using 16 gauge wire. The maximum length of cable used in the Plant Hatch ATTS design is 1800 ft, utilizing 16 gauge wire.

3.A.2.e QUESTION 1-6:

Please provide the applicability of Regulatory Guide 1.75 and IEEE 279-1971 with regard to the Plant Hatch ATTS installation.

RESPONSE:

The ATTS design and installation meet the standards of IEEE 279-1971.

GPC is not committed to meet the requirements of Regulatory Guide 1.75 in the original licensing bases. However, with regard to ATTS, GPC attempted to meet Regulatory Guide 1.75 to the maximum practical extent.

However, the ATTS installation does not completely meet Regulatory Guide 1.75 criteria. For example, as discussed in the Response to Question 1-2, there are non-Class 1E loads being powered from Class 1E buses with a circuit breaker as the separation device. As stated earlier, this is consistent with the original design bases for Plant Hatch, inasmuch as Plant Hatch is not a Regulatory Guide 1.75 plant.

Divisional separation is maintained within the cabinet. Class 1E/non-Class 1E separation is carried through up to the trip relay. The annunciator trip relays are the separation point between 1E and non-1E; that separation is via the contact to coil separation within the relay.

Within the cabinets, the minimum separation distance is 6 in. up to the relay. Within the relay, one is limited to the distance from the contact to the coil.

The ATTS has been installed consistent with the requirements of Chapter 8 of the FSAR and 10 CFR 50, Appendix R.

TABLE 3.1 (SHEET 1 OF 8)

INSTRUMENT LOOP INFORMATION

Variable Name[a]	Trip Unit MPL No.	Primary Sensor Old MPL No.	Primary Sensor New MPL No.	Engineering Safeguard Division	Existing Device Manufacturer	Existing Device Model No.	New Device Generic Name	New Device Manufacturer	New Device Model No.[c]	Associated Rack[b]
1) Reactor Steam Dome Pressure High (LLS Arming Logic Permissive)	B21-N620 A,B,C,D	NA	B21-N120 A,B,C,D	ECCS	NA	NA	Pressure Transmitter	Rosemount	(d)	A,C-H21-P404A/B B,D-H21-P405A/B
2) Low Low Set Control Permissive	B21-N621* A,B,C,D	NA	B21-N120 A,B,C,D	ECCS	NA	NA	Slave	NA	NA	NA
3) Low Low Set Control Permissive	B21-N622 A,B,C,D	NA	B21-N122 A,B,C,D	ECCS	NA	NA	Pressure Transmitter	Rosemount	(d)	A,C-H21-P404A/B B,D-H21-P405A/B
4) Steam Tunnel Temperature High	B21-N623 A,B,C,D	B21-N010 A,B,C,D	B21-N123 A,B,C,D	RPS	Fenwall	17002-40	RTD	Weed	1AOD	Local
5) Steam Tunnel Temperature High	B21-N624 A,B,C,D	B21-N011 A,B,C,D	B21-N124 A,B,C,D	RPS	Fenwall	17002-40	RTD	Weed	1AOD	Local
6) Steam Tunnel Temperature High	B21-N625 A,B,C,D	B21-N012 A,B,C,D	B21-N125 A,B,C,D	RPS	Fenwall	17002-40	RTD	Weed	1AOD	Local
7) Steam Tunnel Temperature High	B21-N626 A,B,C,D	B21-N013 A,B,C,D	B21-N126 A,B,C,D	RPS	Fenwall	17002-40	RTD	Weed	1AOD	Local
8) Reactor Vessel Pressure Low	B21-N641* B,C	B21-N021 B,C,	B21-N090 B,C	ECCS	Barton	288	Slave	NA	NA	NA
9) Reactor Vessel Steam Dome Pressure High	B21-N678 A,B,C,D	B21-N023 A,B,C,D	B21-N078 A,B,C,D	RPS	Barksdale	B2T-M12SS	Pressure Transmitter	Rosemount	(d)	A,B-H21-P404C/D C,D-H21-P405C/D

* Slave trip unit.

a. Transmitters having the same MPL No. are the same equipment providing several trip functions.

b. Separated for divisional considerations.

c. The complete RTD model number for all present RTD applications is 1AOD/611-[illegible]B-C-6-C-[illegible]-A2-0.

d. Pressure transmitter model number 1153GB8PAN0019.

TABLE 3.1 (SHEET 2 OF 8)

INSTRUMENT LOOP INFORMATION

Variable Name[a]	Trip Unit MPL No.	Primary Sensor: Old MPL No.	Primary Sensor: New MPL No.	Engineering Safeguard Division	Existing Device: Manufacturer	Existing Device: Model No.	New Device: Generic Name	New Device: Manufacturer	New Device: Model No.[c]	Associated Rack[b]
10) Reactor Vessel Steam Dome Pressure Low	B31-N679 A	B31-N018 A	B31-N079 A	RPS	Barksdale	B2T-M12SS	Differential Pressure Transmitter	Barton	764	Local
	B31-N679 D	B31-N018 B	B31-N079 D	RPS	Static-O-Ring	SN-A33-(X9)STT	Differential Pressure Transmitter	Barton	764	Local
11) Reactor Vessel Water Level Low (Level 3)	B21-N680 A,B,C,D	B21-N017 A,B,C,D	B21-N080 A,B,C,D	RPS	Barton	288A	Differential Pressure Transmitter	Barton	764	A,B-H21-P404C/D C,D-H21-P405C/D
12) Reactor Vessel Water Level Low Low Low (Level 1)	B21-N681 A,B	B21-N024** A,B	B21-N081 A,B	RPS	Yarway	4418C	Differential Pressure Transmitter	Barton	764	A,B-H21-P404C/D
	B21-N681 C,D	B21-N025** A,B	B21-N081 C,D	RPS	Yarway	4418C	Differential Pressure Transmitter	Barton	764	C,D-H21-P405C/D
13) Reactor Vessel Water Level Low Low (Level 2)	B21-N682* A,B	B21-N024** A,B	B21-N081 A,B	RPS	Yarway	4418C	Slave	NA	NA	NA
	B21-N682* C,D	B21-N025** A,B	B21-N081 C,D	RPS	Yarway	4418C	Slave	NA	NA	NA
14) Reactor Shroud Water Level Low (Level 0)	B21-N685# A,B	B21-N036 B21-N037	B21-N085 A,B	ECCS	Yarway	4418CE	Differential Pressure Transmitter	Barton	764	A-H21-P409 B-H21-P410
15) Main Steam Line A Flow High	B21-N686 A,B,C,D	B21-N006 A,B,C,D	B21-N086 A,B,C,D	RPS	Barton	288 Transmitter	Differential Pressure	Barton	764	A,B-H21-P415A/B C,D-H21-P425A/B

* Slave trip unit.

** Not being deleted; only the safety function is being replaced by ATTS. Performs recirculation pump trip only.

\# Provide analog output for reactor water level indication and recording.

a. Transmitters having the same MPL No. are the same equipment providing several trip functions.

b. Separated for divisional considerations.

c. The complete RTD model number for all present RTD applications is 1A0D/611-1B-C-6-C-2-A2-0.

TABLE 3.1 (SHEET 3 OF 8)

INSTRUMENT LOOP INFORMATION

	Variable Name[a]	Trip Unit MPL No.	Primary Sensor Old MPL No.	Primary Sensor New MPL No.	Engineering Safeguard Division	Existing Device Manufacturer	Existing Device Model No.	New Device Generic Name	New Device Manufacturer	New Device Model No.[c]	Associated Rack[b]
16)	Main Steam Line B Flow High	B21-N687 A,B,C,D	B21-N007 A,B,C,D	B21-N087 A,B,C,D	RPS	Barton	288	Differential Pressure Transmitter	Barton	764	A,B-H21-P415A/B C,D-H21-P425A/B
17)	Main Steam Line C Flow High	B21-N688 A,B,C,D	B21-N008 A,B,C,D	B21-N088 A,B,C,D	RPS	Barton	288	Differential Pressure Transmitter	Barton	764	A,B-H21-P415A/B C,D-H21-P425A/B
18)	Main Steam Line D Flow High	B21-N689 A,B,C,D	B21-N009 A,B,C,D	B21-N089 A,B,C,D	RPS	Barton	288	Differential Pressure Transmitter	Barton	764	A,B-H21-P415A/B C,D-H21-P425A/B
19)	Reactor Vessel Pressure Low	B21-N690## A,D,E,F	B21-N021 A,D,E,F	B21-N090 A,D,E,F	ECCS	Barksdale	B2T-M12SS	Pressure Transmitter	Barton	763	A,E-H21-P404A D,F-H21-P405A
		B21-N690 B,C	B21-N021 B,C	B21-N090 B,C	ECCS	Barton	288	Pressure Transmitter	Rosemount	1153GB9RJ	B-H21-P410 C-H21-P409
20)	Reactor Vessel Water Level Low Low Low (Level 1)	B21-N691# A,B,C,D	B21-N031 A,B,C,D	B21-N091 A,B,C,D	ECCS	Yarway	4418C	Differential Pressure Transmitter	Barton	764	A,C-H21-P404A B,D-H21-P405A
21)	Reactor Vessel Water Level Low Low (Level 2)	B21-N692* A,B,C,D	B21-N031 A,B,C,D	B21-N091 A,B,C,D	ECCS	Yarway	4418C	Slave	NA	NA	NA
22)	Reactor Vessel Water Level High (Level 8)	B21-N693 A,B	B21-N017 A,B	B21-N093 A,B	ECCS	Barton	288A	Differential Pressure Transmitter	Rosemount	(d)	Local
		B21-N693* C,D	B21-N017 C,D	B21-N095 A,B	ECCS	Barton	288A	Slave	NA	NA	NA

* Slave trip unit.

\# B21-N691A,B will provide analog output for reactor water level indication and replace B21-N026A,B. B21-N691C,D will provide analog reaction water level recorder inputs and replace B21-N626C,D.

\## B21-N690A,D will provide analog input for reactor pressure recorder inputs and replace B21-N051A,B.

a. Transmitters having the same MPL No. are the same equipment providing several trip functions.

b. Separated for divisional considerations.

c. The complete RTD model number for all present RTD applications is 1AOD/611-1B-C-6-C-2-A2-0.

d. Pressure transmitter model number 1153DB4PA

TABLE 3.1 (SHEET 4 OF 8)

INSTRUMENT LOOP INFORMATION

Variable Name[a]	Trip Unit MPL No.	Primary Sensor Old MPL No.	Primary Sensor New MPL No.	Engineering Safeguard Division	Existing Device Manufacturer	Existing Device Model No.	New Device Generic Name	New Device Manufacturer	New Device Model No.[c]	Associated Rack[b]
23) Reactor Vessel Water Level Low (Level 3)	B21-N695 A,B	B21-N042 A,B	B21-N095 A,B	ECCS	Yarway	4418C	Differential Pressure Transmitter	Barton	764	A-H21-P404B B-H21-P405B
24) Drywell Pressure High	C71-N650 A,B,C,D	C71-N002 A,B,C,D	C71-N050 A,B,C,D	RPS	Static-O-Ring	12N-BB4-NX	Differential Pressure Transmitter	Barton	764	Local
25) RHR Pump Discharge Pressure High	E11-N655 A,C	E11-N016 A,C	E11-N055 A,C	ECCS	Barksdale	B2T-M12SS	Pressure Transmitter	Barton	763	Local
	E11-N655 B,D	E11-N016 B,D	E11-N055 B,D	ECCS	Static-O-Ring	5N-AA3-(X10)SITT	Pressure Transmitter	Barton	763	Local
26) RHR Pump Discharge Pressure High	E11-N656 A,C	E11-N020 A,C	E11-N056 A,C	ECCS	Barksdale	B2T-M12SS	Pressure Transmitter	Barton	763	Local
	E11-N656 B,D	E11-N020 B,D	E11-N056 B,D	ECCS	Static-O-Ring	5N-AA3-(X10)SITT	Pressure Transmitter	Barton	763	Local
27) RHR Pump Flow Low	E11-N682 A,B	E11-N021 A,B	E11-N082 A,B	ECCS	Barton	289	Differential Pressure Transmitter	Barton	764	Local
28) Drywell Pressure High	E11-N694 A,B,C,D	E11-N010 A,B,C,D	E11-N094 A,B,C,D	ECCS	Static-O-Ring	12N-AA5-(X9)TT	Differential Pressure Transmitter	Barton	764	Local
		E11-N011# A,B,C,D								
29) Core Spray Pump Discharge Flow Low	E21-N651 A,B	E21-N006 A,B	E21-N051 A,B	ECCS	Barton	289	Differential Pressure Transmitter	Barton	764	Local

\# Deleted from plant. Functions of E11-N011A,B,C,D assigned to E11-N010A,B,C,D.

a. Transmitters having the same MPL No. are the same equipment providing several trip functions.

b. Separated for divisional considerations.

c. The complete RTD model number for all present RTD applications is 1A0D/611-1B-C-6-C-2-A2-0.

TABLE 3.1 (SHEET 5 OF 8)

INSTRUMENT LOOP INFORMATION

Variable Name[a]	Trip Unit MPL No.	Primary Sensor Old MPL No.	Primary Sensor New MPL No.	Engineering Safeguard Division	Existing Device Manufacturer	Existing Device Model No.	New Device Generic Name	New Device Manufacturer	New Device Model No.[c]	Associated Rack[b]
30) Core Spray Pump Discharge Pressure High	E21-N652 A,B	E21-N009 A,B	E21-N052 A,B	ECCS	Barksdale	B2T-M12SS	Pressure Transmitter	Barton	763	Local
31) Core Spray Pump Discharge Pressure High	E21-N655 A,B	E21-N008 A,B	E21-N055 A,B	ECCS	Static-O-Ring	5N-AA3-(X10)SITT	Pressure Transmitter	Barton	763	Local
32) HPCI Pump Pressure High	E41-N650	E41-N027	E41-N050	ECCS	Barksdale	B2T-M12SS	Pressure Transmitter	Barton	763	H21-P414B
33) HPCI Pump Discharge Flow High	E41-N651	E41-N006	E41-N051	ECCS	Barton	288	Differential Pressure Transmitter	Barton	764	H21-P414A
34) HPCI Pump Suction Pressure Low	E41-N653# E41-N654*	E41-N010 E41-N010	E41-N053 E41-N053	ECCS ECCS	Static-O-Ring	6N-AA21-(X9)VSTT	Differential Pressure Transmitter	Barton	764	H21-P414B
					Static-O-Ring	6N-AA21-(X9)VSTT	Slave		NA	NA
35) HPCI Turbine Exhaust Diaphragm Pressure High	E41-N655 A,B,C,D	E41-N012 A,B,C,D	E41-N055 A,B,C,D	ECCS	Static-O-Ring	6N-AA2-(X10)-SITT	Differential Pressure Transmitter	Barton	764	A,C-H21-P434 B,D-H21-P414A
36) HPCI Turbine Exhaust Pressure High	E41-N656 B,D	E41-N017 A,B,	E41-N056 B,D	ECCS	Static-O-Ring	5N-AA3-(X10)SITT	Pressure Transmitter	Barton	763	H21-P414B
37) HPCI Steam Line Differential Pressure High (+)	E41-N657 A,B	E41-N004 E41-N005	E41-N057 A,B	ECCS	Barton	288	Differential Pressure Transmitter	Barton	764	A-H21-P016 B-H21-P036

* Slave trip unit.

\# E41-N654 is a slave trip unit from E41-N653 and provides an alarm function.

a. Transmitters having the same MPL No. are the same equipment providing several trip functions.

b. Separated for divisional considerations.

c. The complete RTD model number for all present RTD applications is 1AOD/611-1B-C-6-C-2-A2-0.

TABLE 3.1 (SHEET 6 OF 8)

INSTRUMENT LOOP INFORMATION

Variable Name[a]	Trip Unit MPL No.	Primary Sensor Old MPL No.	Primary Sensor New MPL No.	Engineering Safeguard Division	Existing Device Manufacturer	Existing Device Model No.	New Device Generic Name	New Device Manufacturer	New Device Model No.[c]	Associated Rack[b]
38) HPCI Steam Supply Pressure Low	E41-N658 A,B,C,D	E41-N001 A,B,C,D	E41-N058 A,B,C,D	ECCS	Barksdale	B2T-M12SS	Pressure Transmitter	Barton	763	A,C-H21-P016 B,D-H21-P036
39) HPCI Steam Line Differential Pressure High (-)	E41-N660* A,B	E41-N004 E41-N005	E41-N057 A,B	ECCS	Barton	288	Slave	NA	NA	NA
40) HPCI Torus Water Level High	E41-N662 B,D	E41-N015 A,B	E41-N062 B,D	ECCS	Robertshaw	83842-A2	Capillary Differential Pressure Transmitter	Barton	764 with Model 352 Capillary Sensors	Local
41) HPCI Equipment Ambient Temperature High	E41-N670 A,B	E41-N030** A,B	E41-N070 A,B	ECCS	Pyco	N145C3224P1 Type T	RTD	Weed	1A0D	Local
42) HPCI Pipe Room Ambient Temperature High	E41-N671 A,B	E41-N046** A,B	E41-N071 A,B	ECCS	Pyco	N145C3224P1 Type T	RTD	Weed	1A0D	Local
43) RCIC Pump Discharge Pressure High	E51-N650	E51-N020	E51-N050	ECCS	Barksdale	B2T-M12SS	Pressure Transmitter	Barton	763	H21-P417B
44) RCIC Pump Flow High	E51-N651	E51-N002	E51-N051	ECCS	Barton	289	Differential Pressure Transmitter	Barton	764	H21-P417A
45) RCIC Turbine Exhaust Pressure High	E51-N656 A,C	E51-N009 A,B	E51-N056 A,C	ECCS	Barksdale	D2H-M80SS	Pressure Transmitter	Barton	763	H21-P417B
46) RCIC Steam Line ΔP High (+)	E51-N657 A,B	E51-N017 E51-N018	E51-N057 A,B	ECCS	Barton	288	Differential Pressure Transmitter	Barton	764	A-H21-P035 B-H21-P038

* Slave trip unit.

** Not being deleted; the safety function is being replaced by ATTS, only the alarm function will be retained.

a. Transmitters having the same MPL No. are the same equipment providing several trip functions.

b. Separated for divisional considerations.

c. The complete RTD model number for all present RTD applications is 1A0D/611-1B-C-6-C-2-A2-0.

TABLE 3.1 (SHEET 7 OF 8)

INSTRUMENT LOOP INFORMATION

Variable Name[a]	Trip Unit MPL No.	Primary Sensor Old MPL No.	Primary Sensor New MPL No.	Engineering Safeguard Division	Existing Device Manufacturer	Existing Device Model No.	New Device Generic Name	New Device Manufacturer	New Device Model No.[c]	New Device Associated Rack[b]
48) RCIC Steam Line P High (-)	E51-N660* A,B	E51-N017 E51-N018	E51-N057 A,B	ECCS	Barton	288	Slave	NA	NA	NA
49) RCIC Equipment Ambient Temperature High	E51-N661 A,B	E51-N023** A,B	E51-N061 A,B	ECCS	Pyco	N145C3224P1 Type T	RTD	Weed	1AOD	Local
50) Torus Ambient Temperature (no trip)	E51-N663 A,B,C,D	E51-N026** A,B,C,D	E51-N063 A,B,C,D	ECCS	Pyco	N145C3224P1 Type T	RTD	Weed	1AOD	Local
	E51-N664 A,B,C,D	E51-N027** A,B,C,D	E51-N064 A,B,C,D	ECCS	Pyco	N145C3224P1 Type T	RTD	Weed	1AOD	Local
51) Torus Ambient Temperature High	E51-N666 A,B,C,D	E51-N025** A,B,C,D	E51-N066 A,B,C,D	ECCS	Pyco	N145C3224P1 Type T	RTD	Weed	1AOD	Local
52) Torus Differential Temperature High	E51-N665 A,B,C,D	E51-N604** A,B,C,D	NA	ECCS	Transmation	630A	RTD	NA	NA	NA
53) RCIC Pump Suction Pressure Low	E51-N683	E51-N006	E51-N083	ECCS	Static-O-Ring	6N-AA21-(X9)VSTT	Differential Pressure Transmitter	Barton	764	H[illegible]1-P[illegible]7B
	E51-N684*	E51-N006	E51-N083	ECCS	Static-O-Ring	6N-AA21-(X9)VSTT	Slave	NA	NA	NA
54) RCIC Turbine Exhaust Diaphragm Pressure High	E51-N685 A,B,C,D	E51-N012 A,B,C,D	E51-N085 A,B,C,D	ECCS	Static-O-Ring	12NN-AAS-M4	Differential Pressure Transmitter	Barton	764	A,C-H21-P417A B,D-H21-P437
55) RWCU Room Temperature Inlet (no trip)	G31-N661 A,E,D,H, J,M	G31-N023** A,B,C,D,	G31-N061 A,E,D,H, J,M	RPS	Pyco	N145C3224P1 Type T	RTD	Weed	1AOD	Local
		G31-N022 E,F		RPS	Pyco	N145C3224P1 Type T	RTD	Weed	1AOD	Local

* Slave trip unit.
** Not being deleted; only the safety function being replaced by ATTS. Alarm function only.

a. Transmitters having the same MPL No. are the same equipment providing several trip functions.

b. Separated for divisional considerations.

c. The complete RTD model number for all present RTD applications is 1AOD/611 1B-C-6-C-2-A2-O.

TABLE 3.1 (SHEET 8 OF 8)

INSTRUMENT LOOP INFORMATION

Variable Name[a]	Trip Unit MPL No.	Primary Sensor Old MPL No.	Primary Sensor New MPL No.	Engineering Safeguard Division	Existing Device Manufacturer	Existing Device Model No.	New Device Generic Name	New Device Manufacturer	New Device Model No.[c]	Associated Rack[b]
56) RWCU Area Ventilation Differential Temperature High	G31-N663 A,E,D,H, J,M	G31-N602** B,C,D,E, A,F	NA	RPS	Transmation	630A	NA	NA	NA	NA
57) RWCU Room Outlet Ambient Temperature High	G31-N662 A,E,D,H, J,M	G31-N022** A,B,C,D, G31-N023 E,F G31-N016** B,C,D,E, A,F	G31-N062 A,E,D,H, J,M	RPS	Pyco	N145C3224P1 Type T	RTD	Weed	1AOD	Local
58) Low Low Set Arming Logic Permissive	NA	NA	B21-N302A B21-N302B B21-N302C B21-N302D B21-N302E B21-N302F B21-N302G B21-N302H B21-N302J B21-N302K B21-N302L	ECCS	NA	NA	Pressure Switch	PCI	A17-1P	Local
59) Low Low Set Arming Logic Permissive	NA	B21-N301A B21-N301B B21-N301C B21-N301D B21-N301E B21-N301F B21-N301G B21-N301H B21-N301J B21-N301K B21-N301L	B21-N301A B21-N301B B21-N301C B21-N301D B21-N301E B21-N301F B21-N301G B21-N301H B21-N301J B21-N301K B21-N301L	ECCS	PCI	A17-1P	Pressure Switch	PCI	A17-1P	Local

** Not being deleted; only the safety function is being replaced by ATTS. Alarm function only.

a. Transmitters having the same MPL No. are the same equipment having several trip settings.

b. Separated for divisional considerations.

c. The complete RTD model number for all present RTD applications is 1AOD/611-1B-C-6-C-2-A2-0.

TABLE 3.2

CORRELATION BETWEEN EQUIPMENT AND MOUNTING LOCATIONS
(For Use With Seismic Figures 3.9 through 3.21)

	Description	Location	Figure
1)	Cabinets H11-P921 to H11-P928	Main Control Room - el 164 ft	3.18, 3.19
2)	Racks		
	MPL No.		
a)	H21-P402	Reactor Building - el 158 ft	3.15, 3.16, 3.17
b)	H21-P404 A-D	Reactor Building - el 158 ft	3.15, 3.16, 3.17
c)	H21-P405 A-D	Reactor Building - el 158 ft	3.15, 3.16, 3.17
d)	H21-P409	Reactor Building - el 130 ft	3.12, 3.13, 3.14
e)	H21-P410	Reactor Building - el 130 ft	3.12, 3.13, 3.14
f)	H21-P414 A/B	Reactor Building - el 87 ft (HPCI Room)	3.9, 3.10, 3.11
g)	H21-P415 A/B	Reactor Building - el 130 ft	3.12, 3.13, 3.14
h)	H21-P016 (Wall)	Reactor Building - el 130 ft	3.15*, 3.16*, 3.17*
i)	H21-P417 A/B	Reactor Building - el 87 ft (RCIC Corner Room)	3.9, 3.10, 3.11
j)	H21-P425 A/B	Reactor Building - el 130 ft	3.12, 3.13, 3.14
k)	H21-P434 (Wall)	Reactor Building - el 87 ft (HPCI Room)	3.12*, 3.13*, 3.14*
l)	H21-P035 (Wall)	Reactor Building - el 130 ft	3.15*, 3.16*, 3.17*
m)	H21-P036 (Wall)	Reactor Building - el 130 ft	3.15*, 3.16*, 3.17*
n)	H21-P437 (Wall)	Reactor Building - el 87 ft (RCIC Corner Room)	3.12*, 3.13*, 3.14*
o)	H21-P038 (Wall)	Reactor Building - el 130 ft	3.15*, 3.18*, 3.17*
3)	Pressure Switches, RTDs	Use Multiple Locations-Plant Hatch Spectrum Peak Envelope Curves	3.20, 3.21
4)	Locally Mounted Transmitters	Use Multiple Locations - Plant Hatch Spectrum Peak Envelope Curves	3.20, 3.21

*The next higher elevation seismic curves should be used for the wall racks.

FIGURE 3.1

ASSIGNED TRIP UNIT LOCATIONS IN ECCS CARD FILES FOR CABINET H11-P925[d]

1	2	3	4	5	6	7	8	9	10	11	12
E51-N658A[a] E51-N058A[b] RCIC STM LN[c] LO PR	E51-N658C E51-N058C RCIC STM LN LO PR	E51-N657A E51-N057A RCIC STM LN HI ΔP(+)	E51-N660A SLAVE RCIC STM LN HI ΔP(-)	E51-N685A E51-N085A RCIC TB EX DIA HI PR	E51-N685C E51-N085C RCIC TB EX DIA HI PR	E51-N656A E51-N056A RCIC TB EX HI PR	E51-N656C E51-N056C RCIC TB EX HI PR	E51-N651 E51-N051 RCIC PUMP HI FLOW	E51-N684 SLAVE RCIC PUMP LO PR ALARM	E51-N683 E51-N083 RCIC PUMP SUC LOW PR	E51-N650 E51-N050 RCIC PUMP HI PR
E41-N658A[a] E41-N058A[b] HPCI STM LN[c] LO PR	E41-N658C E41-N058C HPCI STM LN LO PR	E41-N657A E41-N057A HPCI STM LN HI ΔP(+)	E41-N660A SLAVE HPCI STM LN HI ΔP(-)	E41-N655A E41-N055A HPCI TB EX DIA HI PR	E41-N655C E41-N055C HPCI TB EX DIA HI PR				B21-N620A B21-N120A LLS ARMING LOGIC PERM	B21-N621A SLAVE LLS CONTROL PERM	B21-N622A B21-N122A LLS CONTROL PERM
B21-N691A[a] B21-N091A[b] WTR LVL 1[c] CS/ADS/RHR DIESEL	B21-N692A SLAVE WTR LVL 2 HPCI/RCIC	B21-N693A B21-N093A WTR LVL 8 RCIC	B21-N691C B21-N091C WTR LVL 1 CS/ADS/RHR DIESEL	B21-N692C SLAVE WTR LVL 2 HPCI/RCIC	B21-N693C SLAVE WTR LVL 8 RCIC	B21-N695A B21-N095A WTR LVL 3 ADS	B21-N685A B21-N085A WTR LVL 0 RHR	E11-N682A E11-N082A RHR PUMP A/C LO FLOW	B21-N620C B21-N120C LLS ARMING LOGIC PERM	B21-N621C SLAVE LLS CONTROL PERM	B21-N622C B21-N122C LLS CONTROL PERM

a. Trip unit MPL No.
b. Sensor MPL No.
c. Loop function.
d. Blank spaces denote empty file slots.

FIGURE 3.2[a]

ASSIGNED TRIP UNIT LOCATIONS IN ECCS CARD FILES FOR CABINET H11-P926[b]

1	2	3	4	5	6	7	8	9	10	11	12
E51-N658B E51-N058B RCIC STM LN LO PR	E51-N658D E51-N058D RCIC STM LN LO PR	E51-N657B E51-N057B RCIC STM LN HI ΔP(+)	E51-N660B SLAVE RCIC STM LN HI ΔP(-)	E51-N685B E51-N085B RCIC TB EX DIA HI PR	E51-N685D E51-N085D RCIC TB EX DIA HI PR	E41-N656B E41-N056B HPCI TB EX HI PR	E41-N656D E41-N056D HPCI TB EX HI PR	E41-N651 E41-N051 HPCI PUMP HI FLOW	E41-N654 SLAVE HPCI PUMP LO PR ALARM	E41-N653 E41-N053 HPCI PUMP SUC PR	E41-N650 E41-N050 HPCI PUMP SUC PR
E41-N658B E41-N058B HPCI STM LN LO PR	E41-N658D E41-N058D HPCI STM LN LO PR	E41-N657B E41-N057B HPCI STM LN HI ΔP(+)	E41-N660B SLAVE HPCI STM LN HI ΔP(-)	E41-N655B E41-N055B HPCI TB EX DIA HI PR	E41-N655D E41-N055D HPCI TB EX DIA HI PR	E41-N662B E41-N062B HPCI TORUS HI WTR LVL	E41-N662D E41-N062D HPCI TORUS HI WTR LVL		B21-N620B B21-N120B LLS ARMING LOCIC PERM	N21-N621B SLAVE LLS CONTROL PERM	B21-N662B B21-N122B LLS CONTROL PERM
B21-N691B B21-N091B WTR LVL 1 CS/ADS/RHR DIESEL	B21-N692B SLAVE WTR LVL 2 HPCI/RCIC	B21-N693B B21-N093B WTR LVL 8 HPCI	B21-N691D B21-N091D WTR LVL 1 CS/ADS/RHR DIESEL	B21-N692D SLAVE WTR LVL 2 HPCI/RCIC	B21-N693D SLAVE WTR LVL 8 HPCI	B21-N695B B21-N095B WTR LVL 3 ADS	B21-N685B B21-N085B WTR LVL 0 RHR	E11-N682B E11-N082B RHR PUMP B/D LO FLOW	B21-N620D B21-N120D LLS ARMING LOGIC PERM	B21-N621D SLAVE LLS CONTROL PERM	B21-N622D B21-N122D LLS CONTROL PERM

a. See figure 3.1 for description of nomenclature.
b. Blank spaces denote empty file slots.

FIGURE 3.3[a]

ASSIGNED TRIP UNIT LOCATIONS IN ECCS CARD FILES FOR CABINET H11-P927[b]

1	2	3	4	5	6	7	8	9	10	11	12
E11-N655A E11-N055A RHR PUMP A HI PR	E11-N655C E11-N055C RHR PUMP C HI PR	E11-N656A E11-N056A RHR PUMP A HI PR	E11-N656C E11-N056C RHR PUMP C HI PR	E11-N694A E11-N094A DRYWELL HI PR	E11-N694C E11-N094C DRYWELL HI PR	B21-N690A B21-N090A VESSEL LO PR		B21-N690C B21-N090C VESSEL LO PR	B21-N641C SLAVE VESSEL LO PR	B21-N690E B21-N090E VESSEL LO PR	
E21-N651A E21-N051A CS PUMP A LO FLOW		E21-N655A E21-N055A CS PUMP A HI PR	E21-N652A E21-N052A CS PUMP A HI PR			E51-N663A E51-N063A RCIC TORUS AMB LO(NT)[c]	E51-N664A E51-N064A RCIC TORUS AMB LO(NT)[c]	E51-N665A NA RCIC TORUS HI ΔT	E51-N663C E51-N063C HPCI TORUS AMB LO(NT)[c]	E51-N664C E51-N064C HPCI TORUS AMB LO(NT)[c]	E51-N665C NA HPCI TORUS HI ΔT
E41-N670A E41-N070A HPCI EQUIP AMB HI TMP	E41-N671A E41-N071A HPCI PIPE RM AMB HI TMP		E51-N661A E51-N061A RCIC EQUIP AMB HI TMP			E51-N666A E51-N066A RCIC TORUS AMB HI TMP	E51-N666C E51-N066C HPCI TORUS AMB HI TMP				

a. See figure 3.1 for description of nomenclature.
b. Blank spaces denote empty file slots.
c. (NT) denotes instrument with no trip function.

FIGURE 3.4[a]

ASSIGNED TRIP UNIT LOCATIONS IN ECCS CARD FILES FOR CABINET H11-P928[b]

1	2	3	4	5	6	7	8	9	10	11	12
E11-N655B E11-N055B RHR PUMP B HI PR	E11-N655D E11-N055D RHR PUMP D HI PR	E11-N656B E11-N056B RHR PUMP B HI PR	E11-N656D E11-N056D RHR PUMP D HI PR	E11-N694B E11-N094B DRYWELL HI PR	E11-N694D E11-N094D DRYWELL HI PR	B21-N690B B21-N090B VESSEL LO PR	B21-N641B SLAVE VESSEL LO PR	B21-N690D B21-N090D VESSEL LO PR		B21-N690F B21-N090F VESSEL LO PR	
E21-N651B E21-N051B CS PUMP B LO FLOW		E21-N655B E21-N055B CS PUMP B HI PR	E21-N652B E21-N052B CS PUMP B HI PR			E51-N663B E51-N063B RCIC TORUS AMB LO(NT)[c]	E51-N664B E51-N064B RCIC TORUS AMB HI(NT)[c]	E51-N665B NA RCIC TORUS HI ΔT	E51-N663D E51-N063D HPCI TORUS AMB LO(NT)[c]	E51-N664D E51-N064D HPCI TORUS AMB HI(NT)[c]	E51-N665D NA HPCI TORUS HI ΔT
E41-N670B E41-N070B HPCI EQUIP AMB HI TMP	E41-N671B E41-N071B HPCI PIPE RM AMB HI TMP		E51-N661B E51-N061B RCIC EQUIP AMB HI TMP			E51-N666B E51-N066B RCIC TORUS AMB HI TMP	E51-N666D E51-N066D HPCI TORUS AMB HI TMP				

a. See figure 3.1 for description of nomenclature.
b. Blank spaces denote empty file slots.
c. (NT) denotes instrument with no trip function.

FIGURE 3.5[a]

ASSIGNED TRIP UNIT LOCATIONS IN RPS CARD FILES FOR CABINET H11-P921[b]

1	2	3	4	5	6	7	8	9	10	11	12
B21-N686A B21-N086A MN ST LN A HI FLOW	B21-N687A B21-N087A MN ST LN B HI FLOW	B21-N688A B21-N088A MN ST LN C HI FLOW	B21-N689A B21-N089A MN ST LN D HI FLOW	B21-N680A B21-N080A WTR LVL 3 RPS	B21-N681A B21-N081A WTR LVL 1 MSIV	B21-N682A SLAVE WTR LVL 2 ISOL	B21-N678A B21-N078A VESSEL HI PR	B31-N679A B31-N079A VESSEL LO PR	C71-N650A C71-N050A DRYWELL HI PR		
						B21-N623A B21-N123A STM TUNN HI TMP	B21-N624A B21-N124A STM TUNN HI TMP		B21-N625A B21-N125A STM TUNN HI TMP	B21-N626A B21-N126A STM TUNN HI TMP	
			G31-N661A G31-N061A RWCU RM IN TMP(NT)[c]	G31-N662A G31-N062A RWCU RM OUT AMB HI TMP	G31-N663A NA RWCU AREA HI ΔT	G31-N661E G31-N061E RWCU RM IN TMP(NT)[c]	G31-N662E G31-N062E RWCU RM OUT AMB HI TMP	G31-N663E NA RWCU AREA HI ΔT	G31-N661J G31-N061J RWCU RM IN TMP(NT)[c]	G31-N662J G31-N062J RWCU RM OUT AMB HI TMP	G31-N663J NA RWCU AREA HI ΔT

a. See figure 3.1 for description of nomenclature.
b. Blank spaces denote empty file slots.
c. (NT) denotes instrument with no trip function.

FIGURE 3.6[a]

ASSIGNED TRIP UNIT LOCATIONS IN RPS CARD FILES FOR CABINET H11-P922[b]

1	2	3	4	5	6	7	8	9	10	11	12
B21-N686B B21-N086B MN ST LN A HI FLOW	B21-N687B B21-N087B MN ST LN B HI FLOW	B21-N688B B21-N0[illegible] MN ST Ln C HI FLOW	B21-N689B B21-N089B MN ST LN D HI FLOW	B21-N680B B21-N080B WTR LVL 3 RPS	B21-N681B B21-N081B WTR LVL 1 MSIV	B21-N682B SLAVE WTR LVL 2 ISOL	B21-N678B B21-N078B VESSEL HI PR		C71-N650B C71-N050B DRYWELL HI PR		
						B21-N623B B21-N123B STM TUNN HI TMP	B21-N624B B21-N124B STM TUNN HI TMP		B21-N625B B21-N125B STM TUNN HI TMP	B21-N626B B21-N126B STM TUNN HI TMP	

a. See Figure 3.1 for description of nomenclature.
b. Blank spaces denote empty file slots.

FIGURE 3.7[a]

ASSIGNED TRIP UNIT LOCATIONS IN RPS CARD FILES FOR CABINET H11-P923[b]

1	2	3	4	5	6	7	8	9	10	11	12
B21-N686C B21-N086C MN ST LN A HI FLOW	B21-N687C B21-N087C MN ST LN B HI FLOW	B21-N688C B21-N088C MN ST LN C HI FLOW	B21-N689C B21-N089C MN ST LN D HI FLOW	B21-N680C B21-N080C WTR LVL 3 RPS	B21-N681C B21-N081C WTR LVL 1 MSIV	B21-N682C SLAVE WTR LVL 2 ISOL	B21-N678C B21-N078C VESSEL HI PR		C71-N650C C71-N050C DRYWELL HI PR	•	
						B21-N623C B21-N123C STM TUNN HI TMP	B21-N624C B21-N124C STM TUNN HI TMP		B21-N625C B21-N125C STM TUNN HI TMP	B21-N626C B21-N126C STM TUNN HI TMP	

a. See figure 3.1 for description of nomenclature.
b. Blank spaces denote empty file slots.

FIGURE 3.8[a]

ASSIGNED TRIP UNIT LOCATIONS IN RPS CARD FILES FOR CABINET H11-P924[b]

1	2	3	4	5	6	7	8	9	10	11	12
B21-N686D B21-N086D MN ST LN A HI FLOW	B21-N687D B21-N087D MN ST LN B HI FLOW	B21-N688D B21-N088D MN ST LN C HI FLOW	B21-N689D B21-N089D MN ST LN D HI FLOW	B21-N680D B21-N080D WTR LVL 3 RPS	B21-N681D B21-N081D WTR LVL 1 MSIV	B21-N682D SLAVE WTR LVL 2 ISOL	B21-N678D B21-N078D VESSEL HI PR	B31-N679D B31-N079D VESSEL LO PR	C71-N650D C71-N050D DRYWELL HI PR		
						B21-N623D B21-N123D STM TUNN HI TMP	B21-N624D B21-N124D STM TUNN HI TMP		B21-N625D B21-N125D STM TUNN HI TMP	B21-N626D B21-N126D STM TUNN HI TMP	
			G31-N661D G31-N061D RWCU RM IN TMP(NT)[c]	G31-N662D G31-N062D RWCU RM OUT AMB HI TMP	G31-N663D NA RWCU AREA HI ΔT	G31-N661H G31-N061H RWCU RM IN TMP(NT)[c]	G31-N662H G31-N062H RWCU RM OUT AMB HI TMP	G31-N663H NA RWCU AREA HI ΔT	G31-N661M G31-N061M RWCU RM IN TMP(NT)[c]	G31-N662M G31-N062M RWCU RM OUT AMB HI TMP	G31-N663M NA RWCU AREA HI ΔT

a. See figure 3.1 for description of nomenclature.
b. Blank spaces denotes empty file slots.
c. (NT) denotes instrument with no trip function.

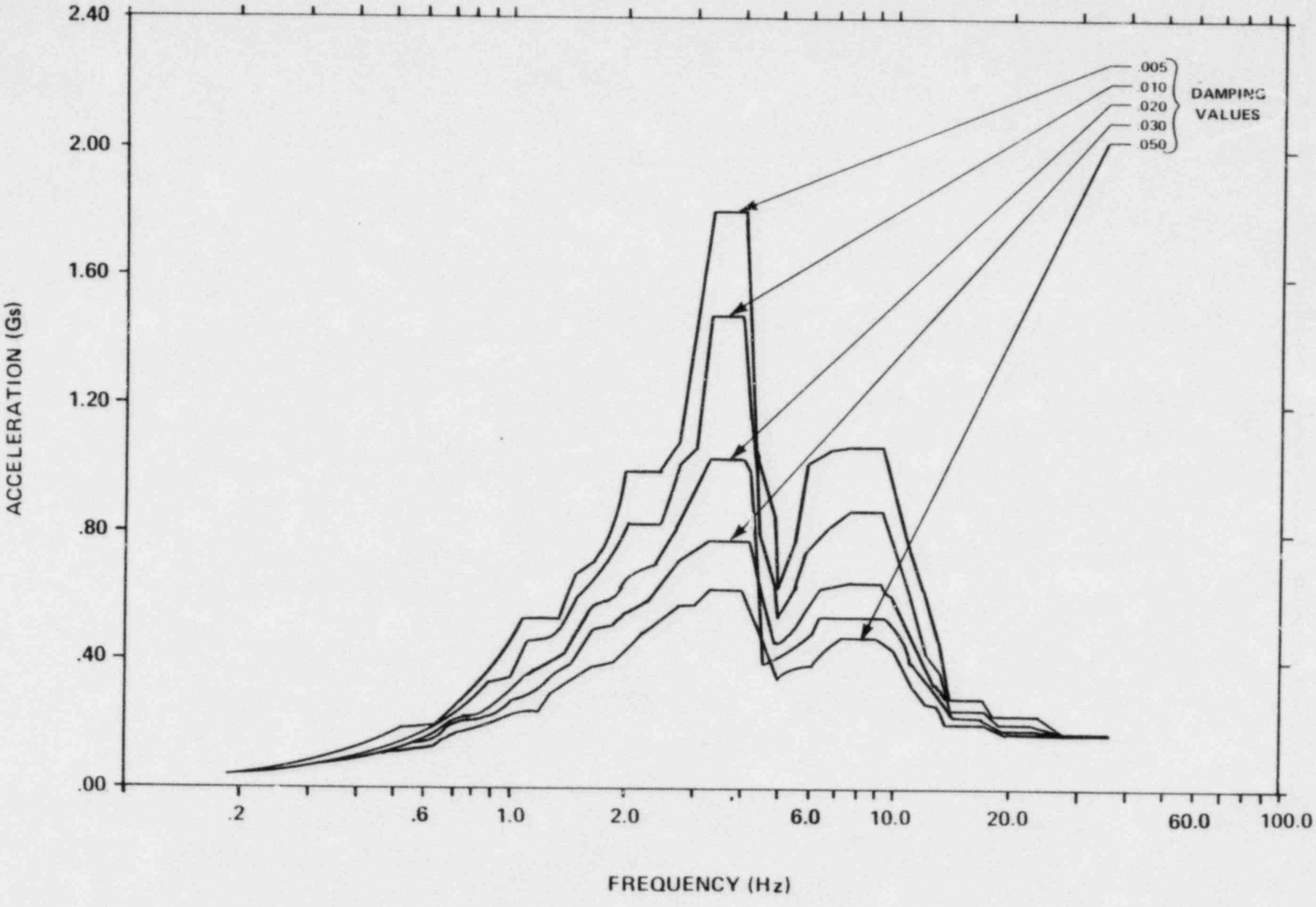


FIGURE 3.9 HNP-2 REACTOR BUILDING EAST-WEST SSE
el 87 ft

9389-2

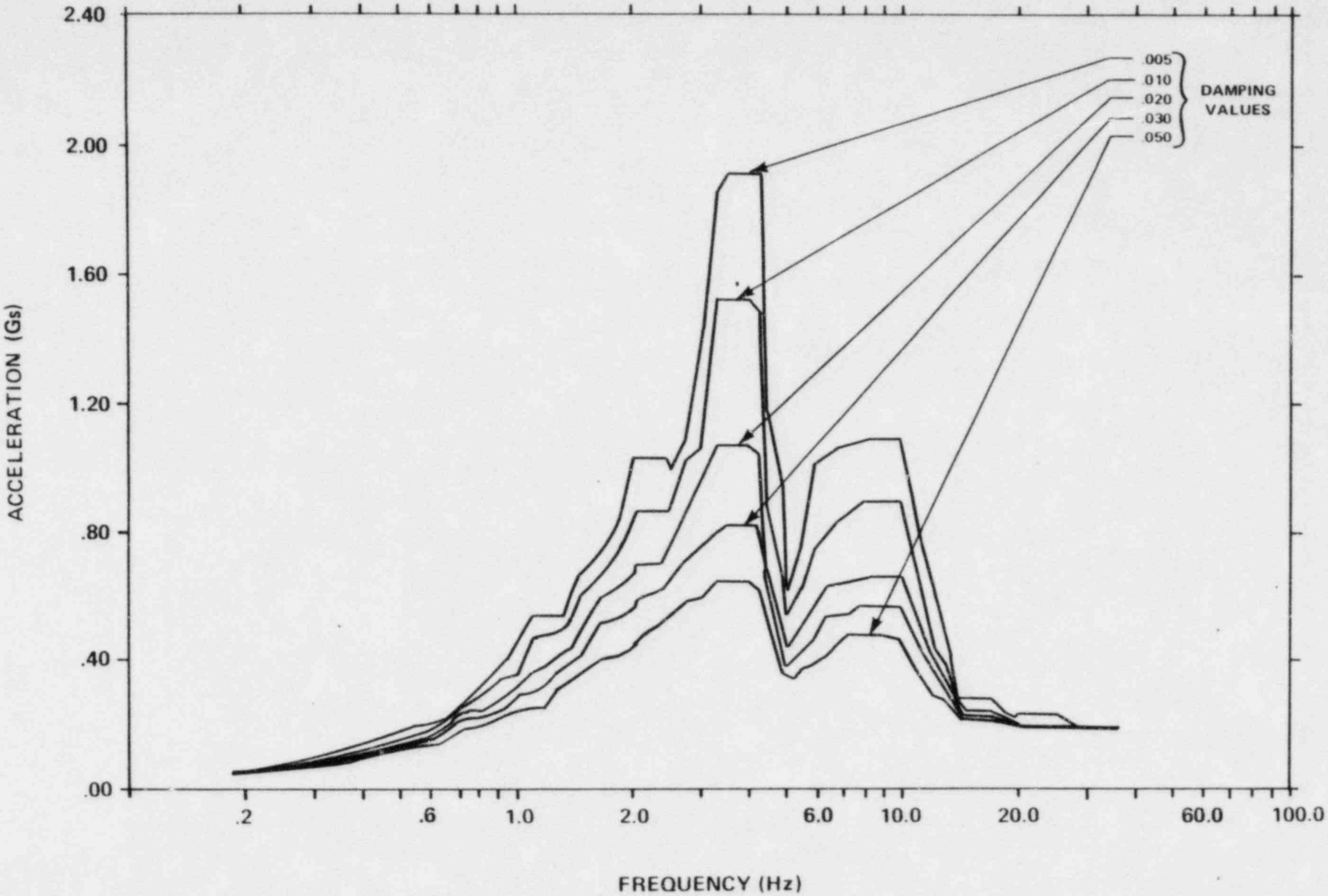


FIGURE 3.10 HNP-2 REACTOR BUILDING NORTH-SOUTH SSE
el 87 ft

9389-2

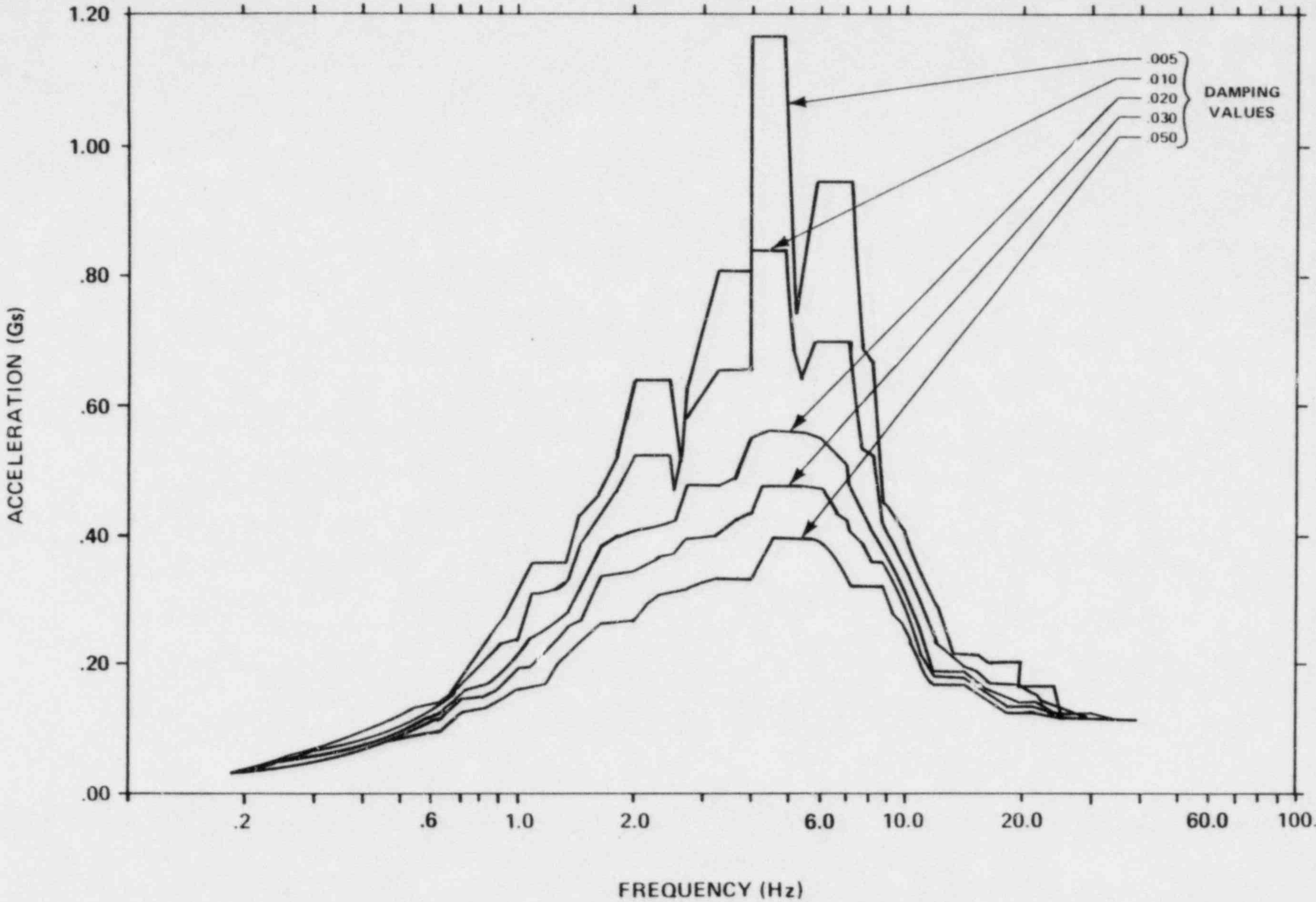


FIGURE 3.11 HNP-2 REACTOR BUILDING VERTICAL SSE
el 87 ft

9389-2

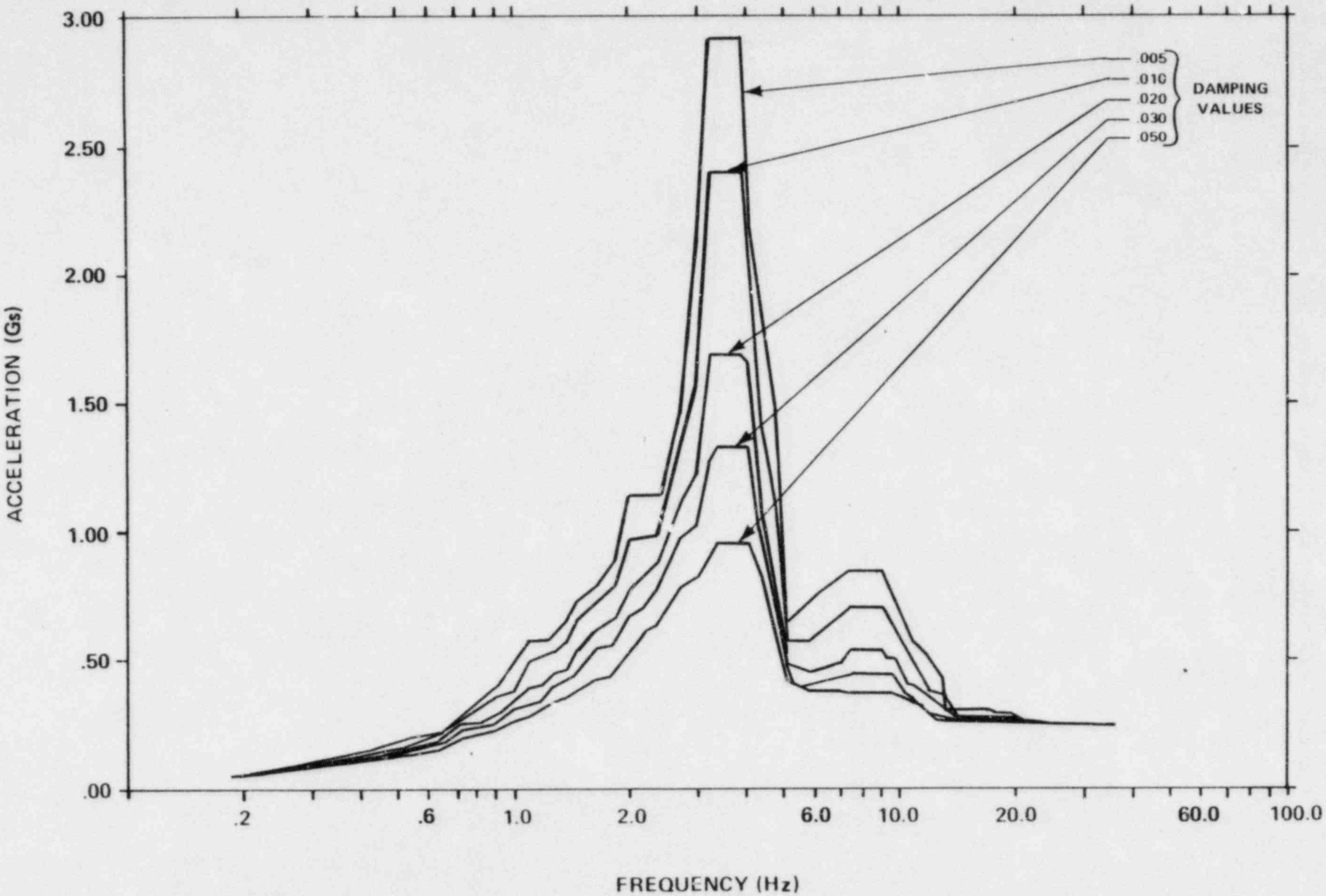


FIGURE 3.12 HNP-2 REACTOR BUILDING EAST-WEST SSE
el 130 ft

9389-2

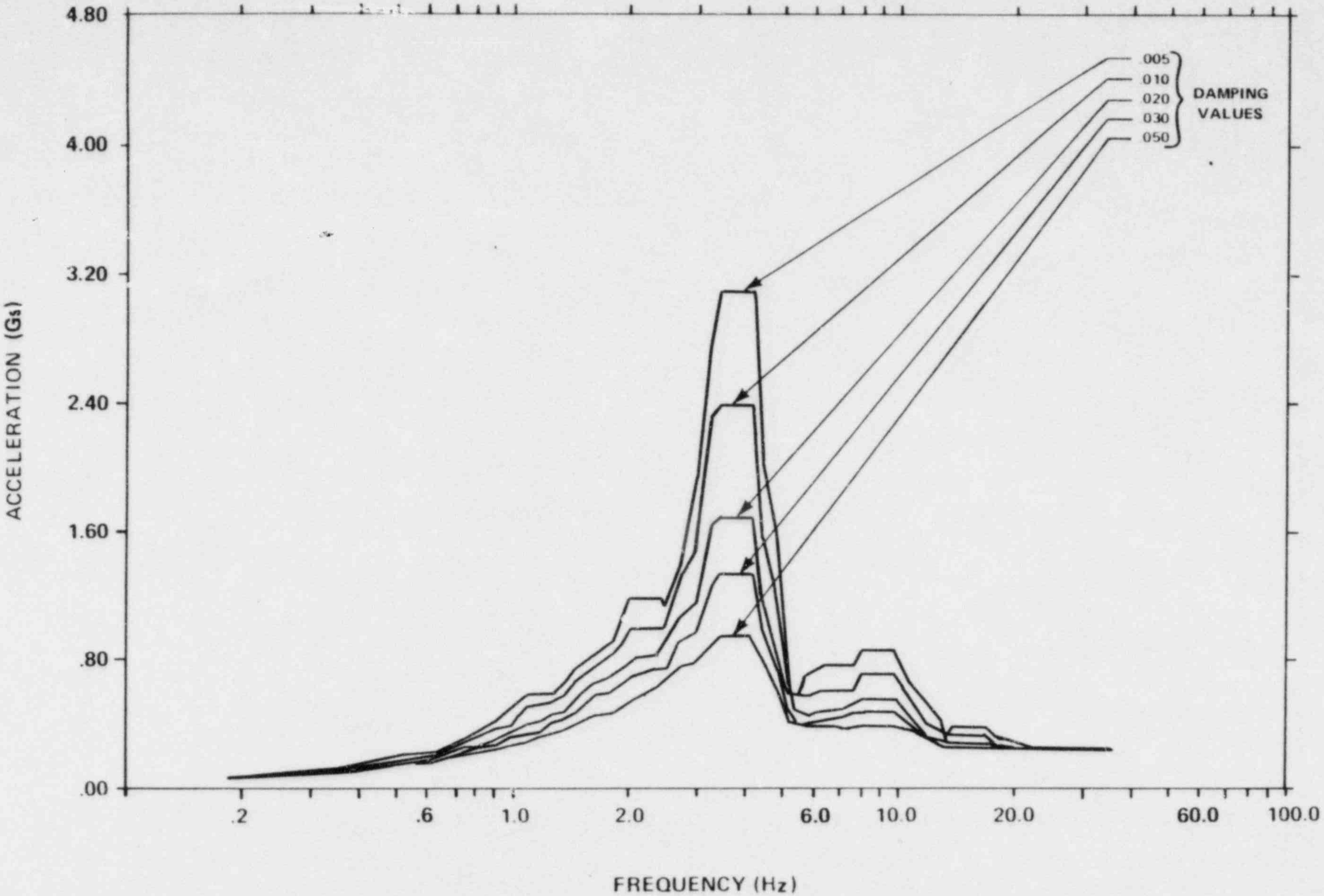


FIGURE 3.13 HNP-2 REACTOR BUILDING NORTH-SOUTH SSE
el 130 ft

9389-2

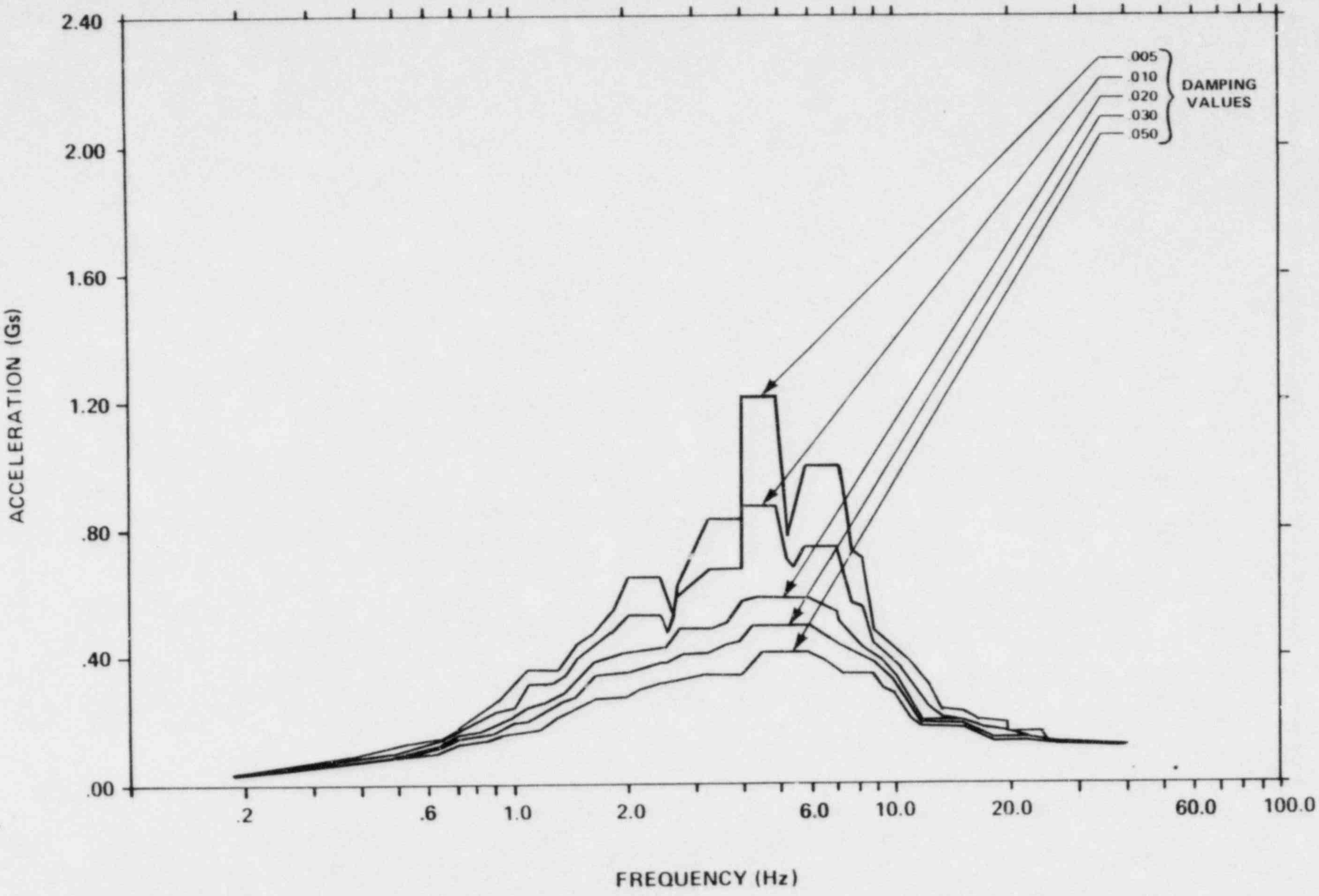


FIGURE 3.14 HNP-2 REACTOR BUILDING VERTICAL SSE
el 130 ft

9389-2

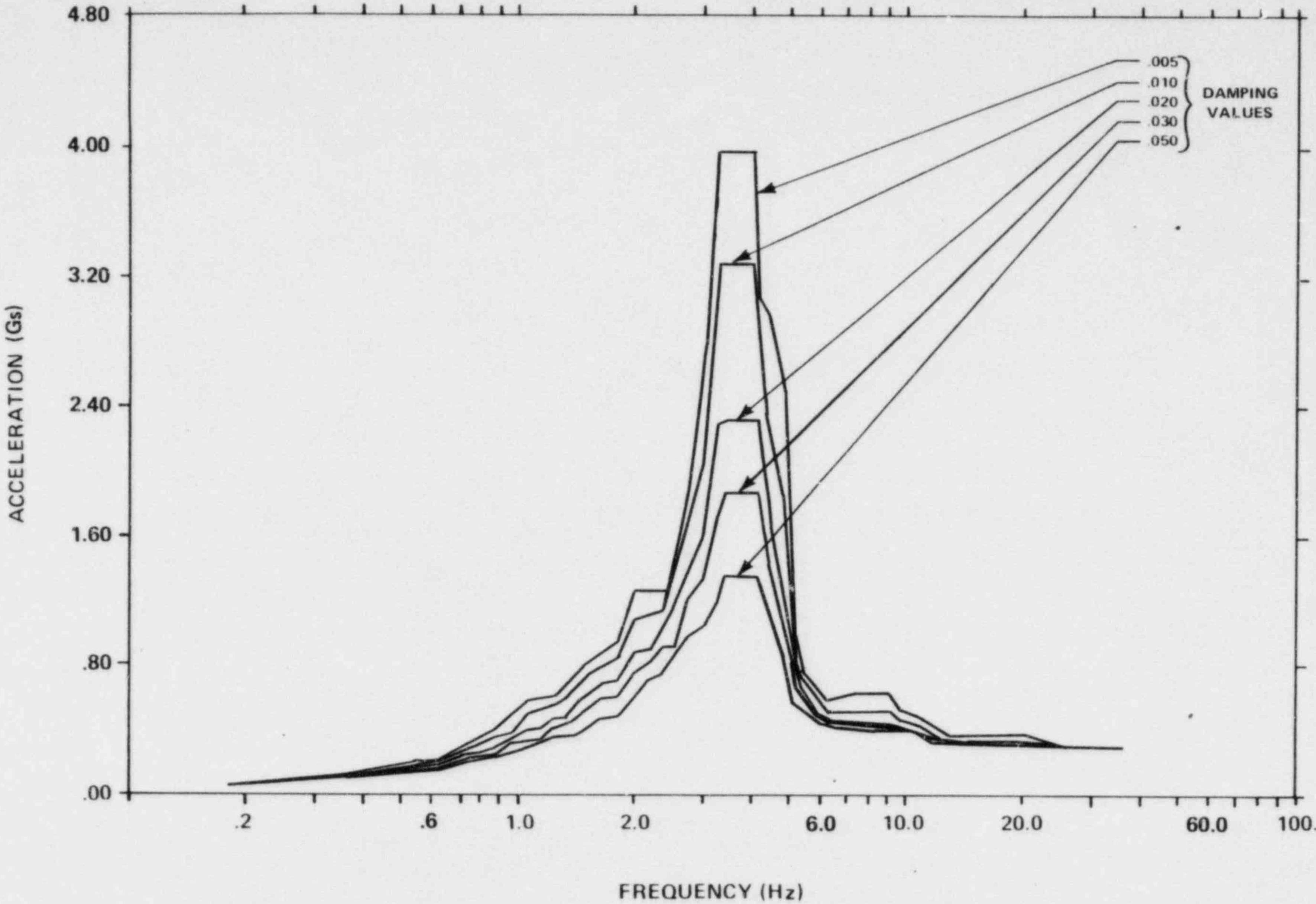


FIGURE 3.15 HNP-2 REACTOR BUILDING EAST-WEST SSE
el 158 ft

9389-2

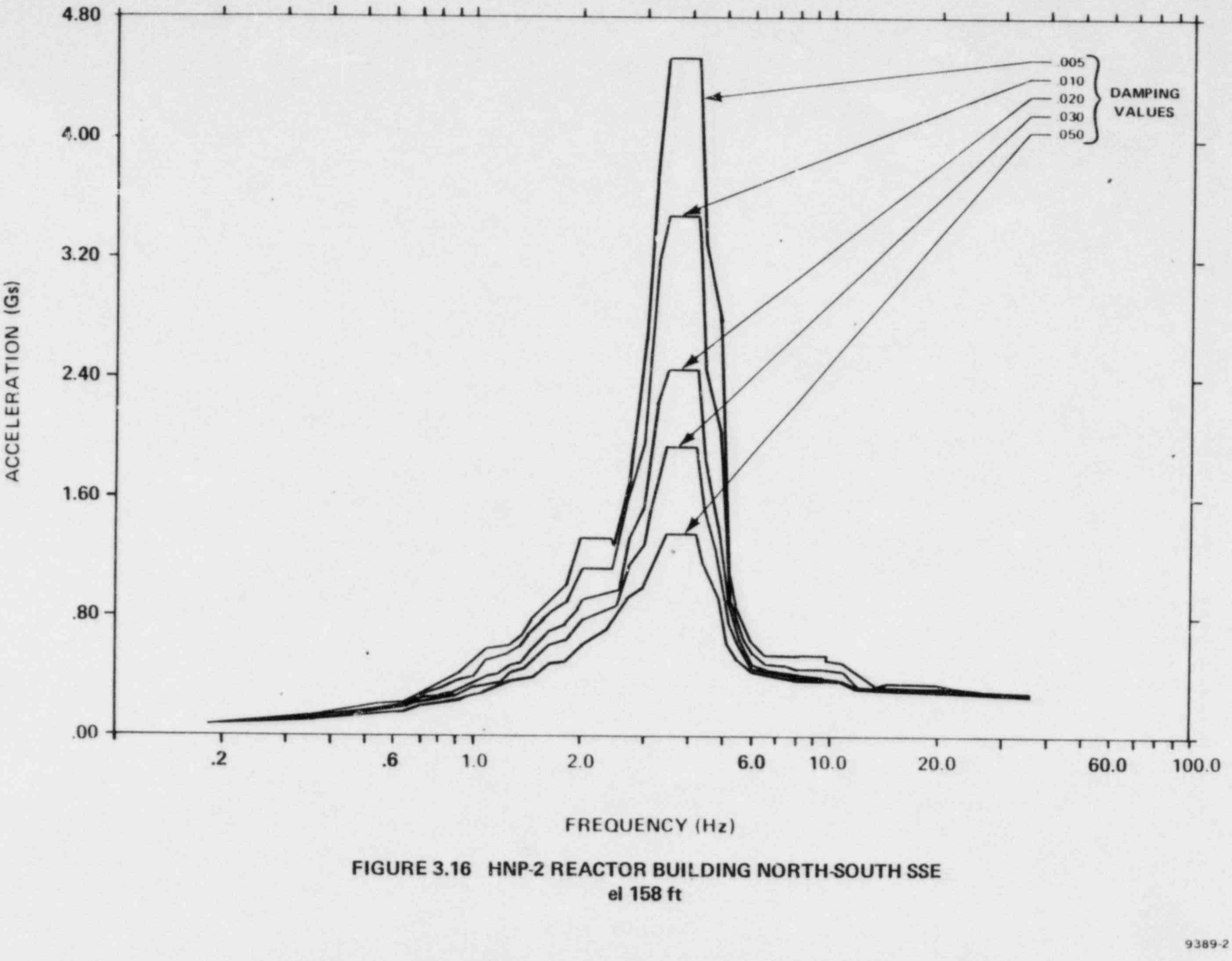


FIGURE 3.16 HNP-2 REACTOR BUILDING NORTH-SOUTH SSE
el 158 ft

9389-2

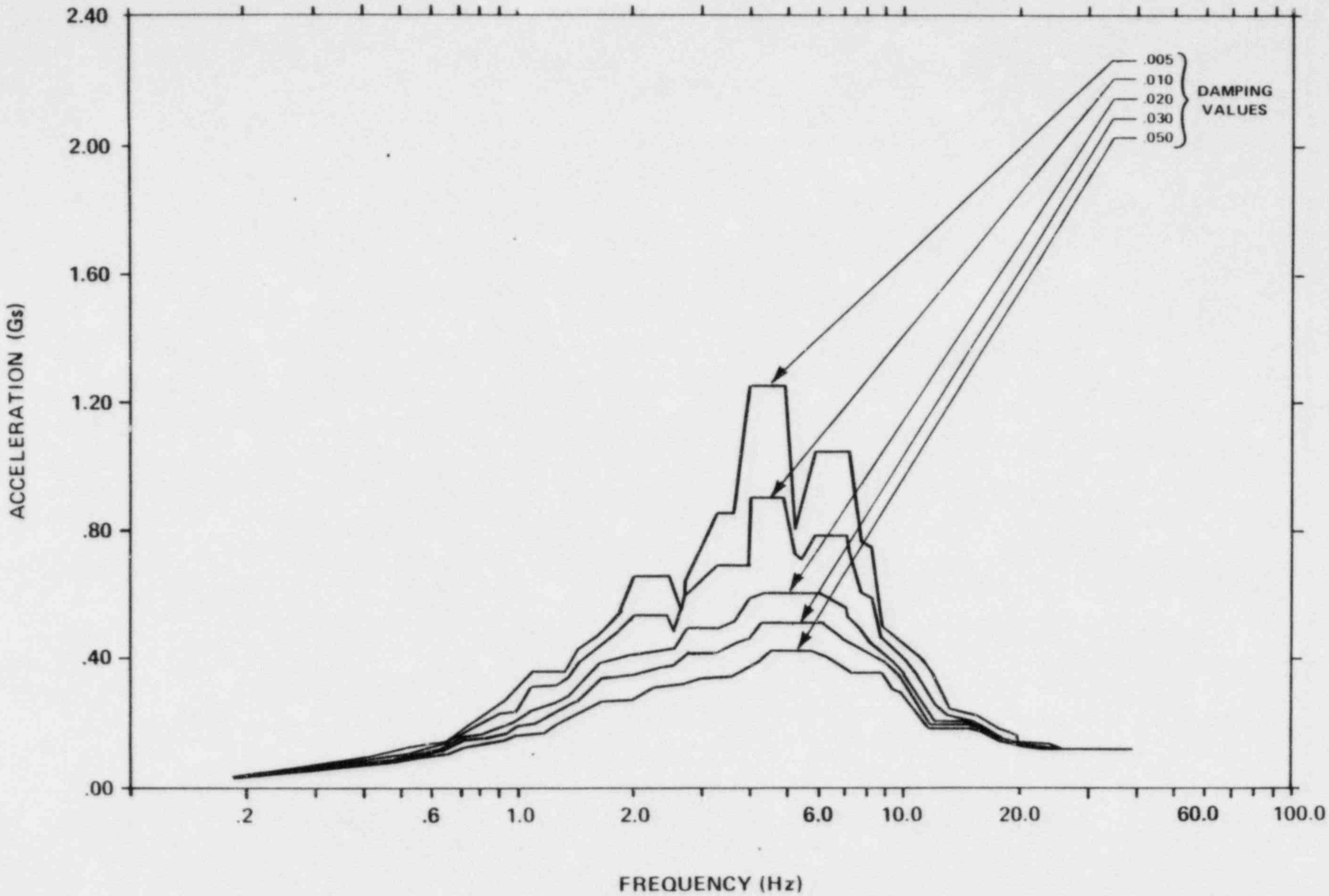


FIGURE 3.17 HNP-2 REACTOR BUILDING VERTICAL SSE
el 158 ft

9389-2

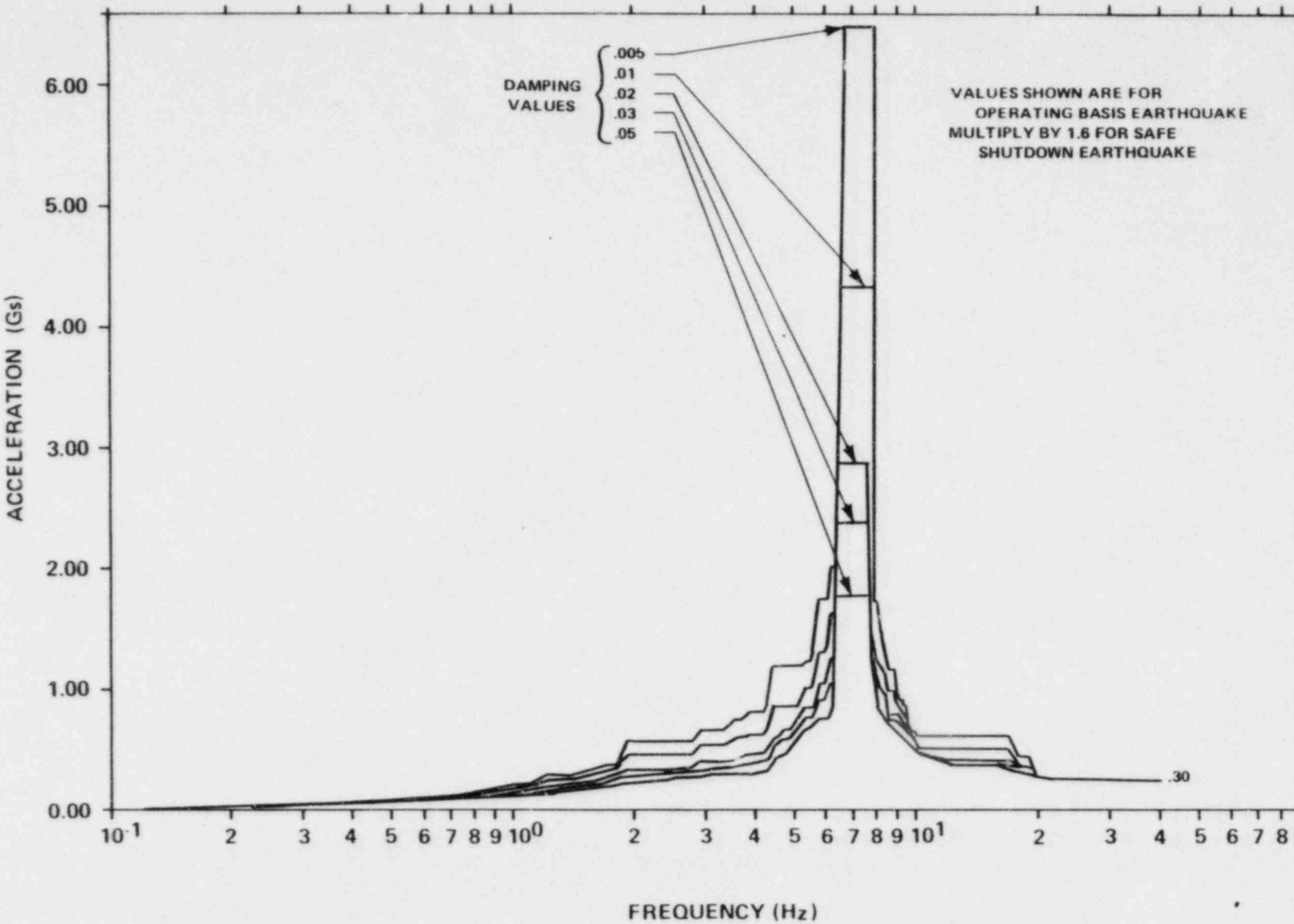


FIGURE 3.18 HNP-2 CONTROL BUILDING HORIZONTAL OBE el 164 ft

9389-2

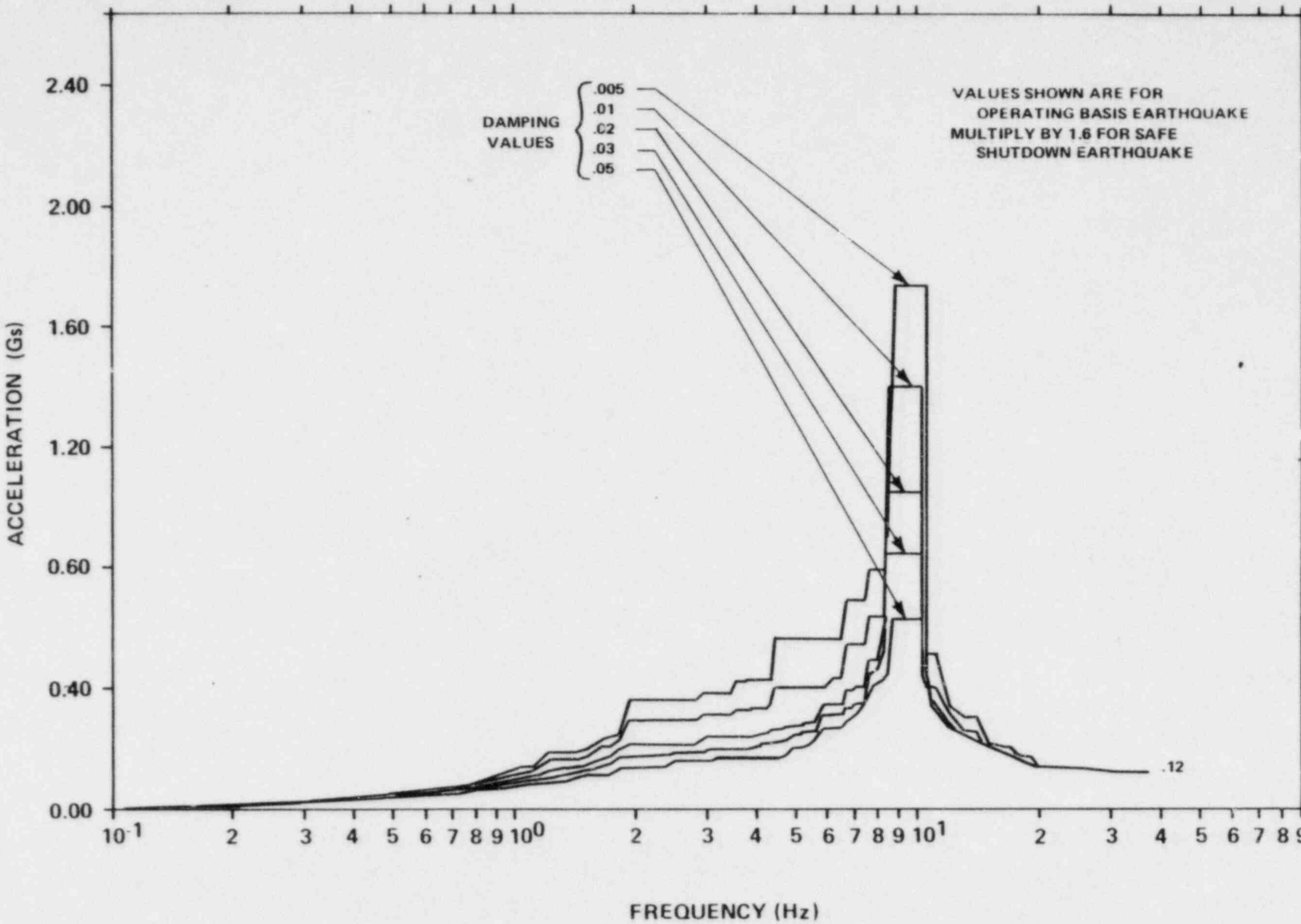


FIGURE 3.19 HNP-2 CONTROL BUILDING VERTICAL OBE
el 164 ft

9389-2

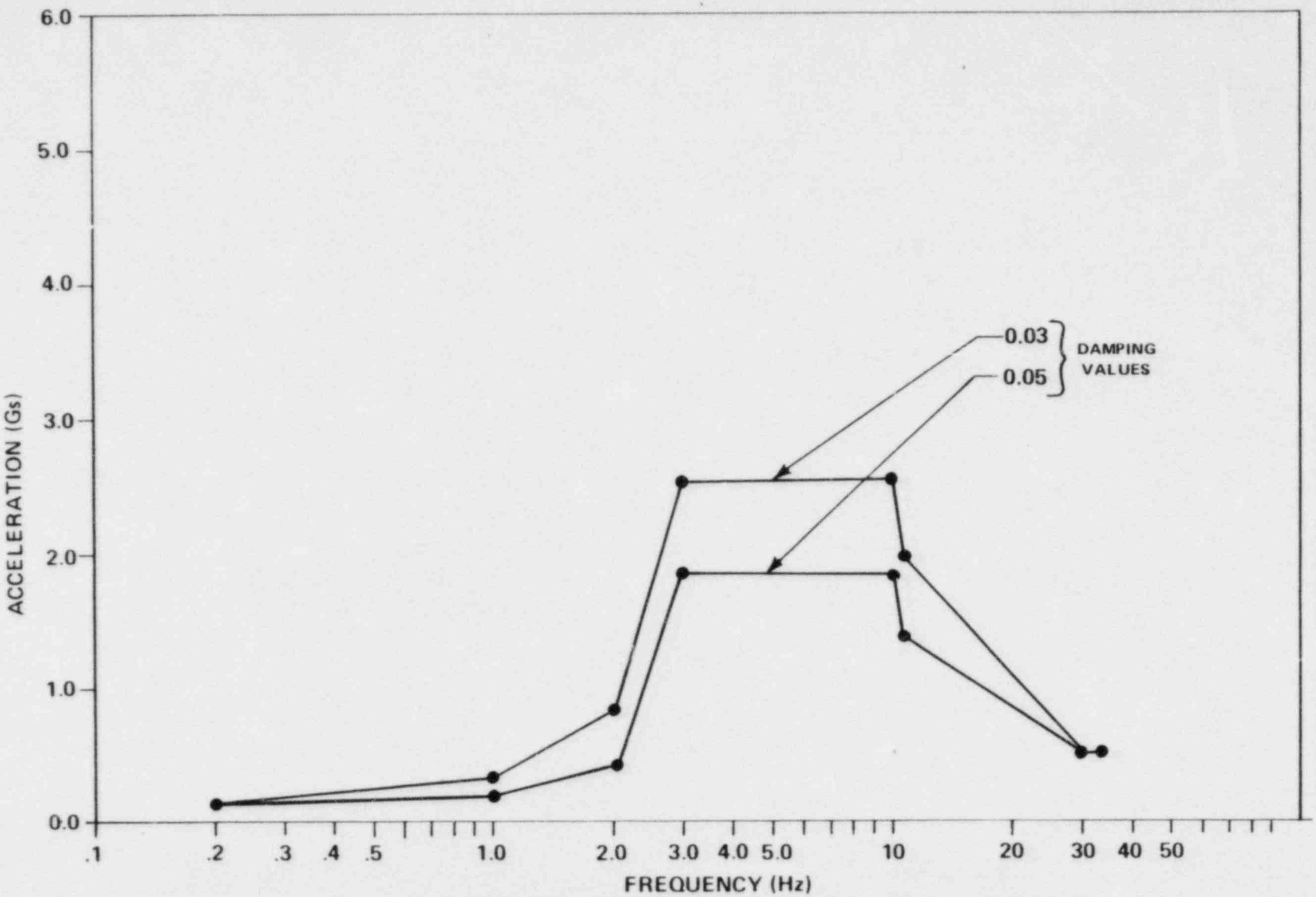


FIGURE 3.20 HNP-2 SSE SPECTRUM PEAK ENVELOPE 3- AND 5- PERCENT DAMPING (VERTICAL)

9389-2

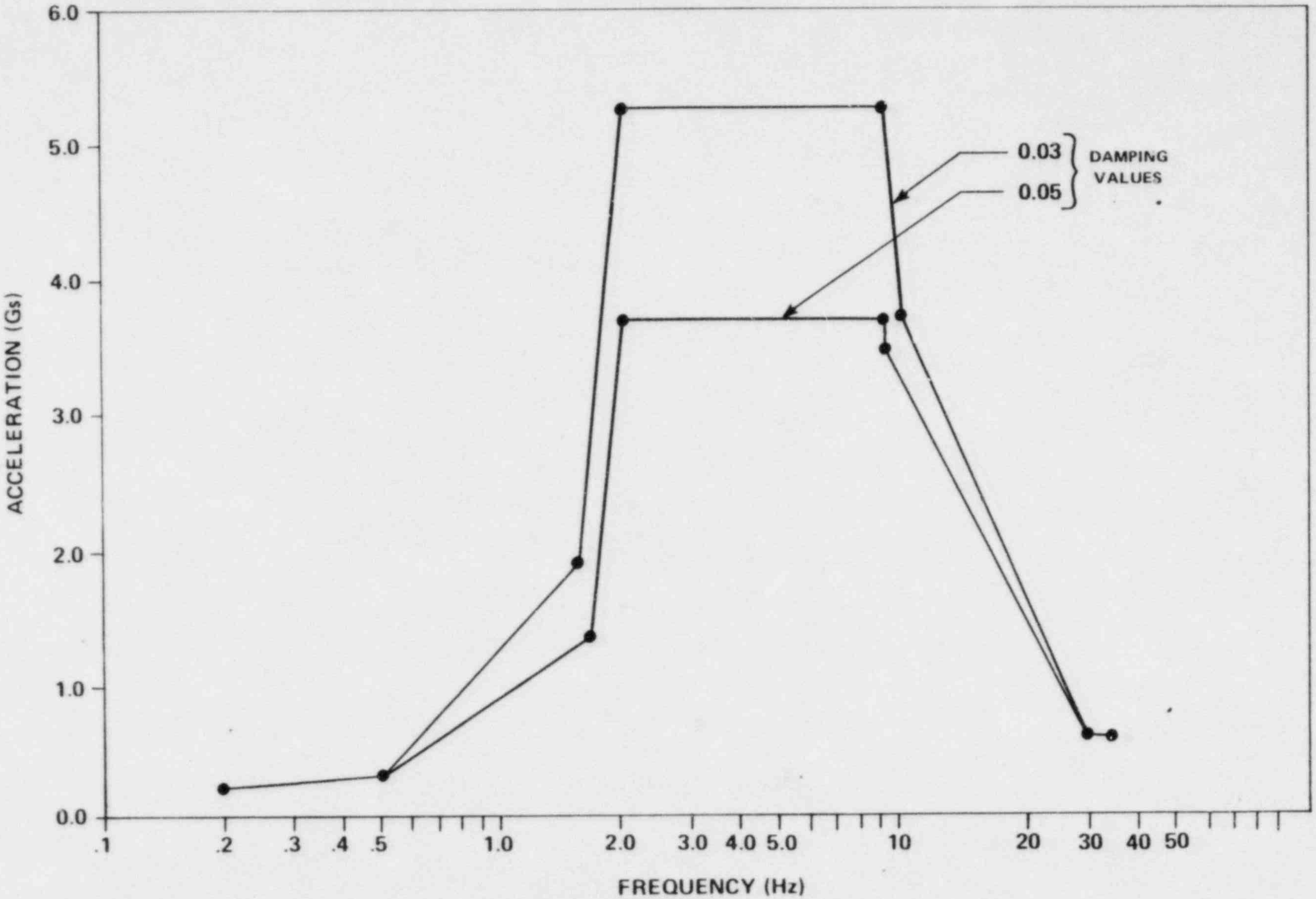


FIGURE 3.21 HNP-2 SSE SPECTRUM PEAK ENVELOPE 3- AND 5- PERCENT DAMPING (HORIZONTAL)

9389-2

FIGURE 3.25 BASIC CABLE ARRANGEMENT & SEPARATION LAYOUT FOR PLANT HATCH ATTS

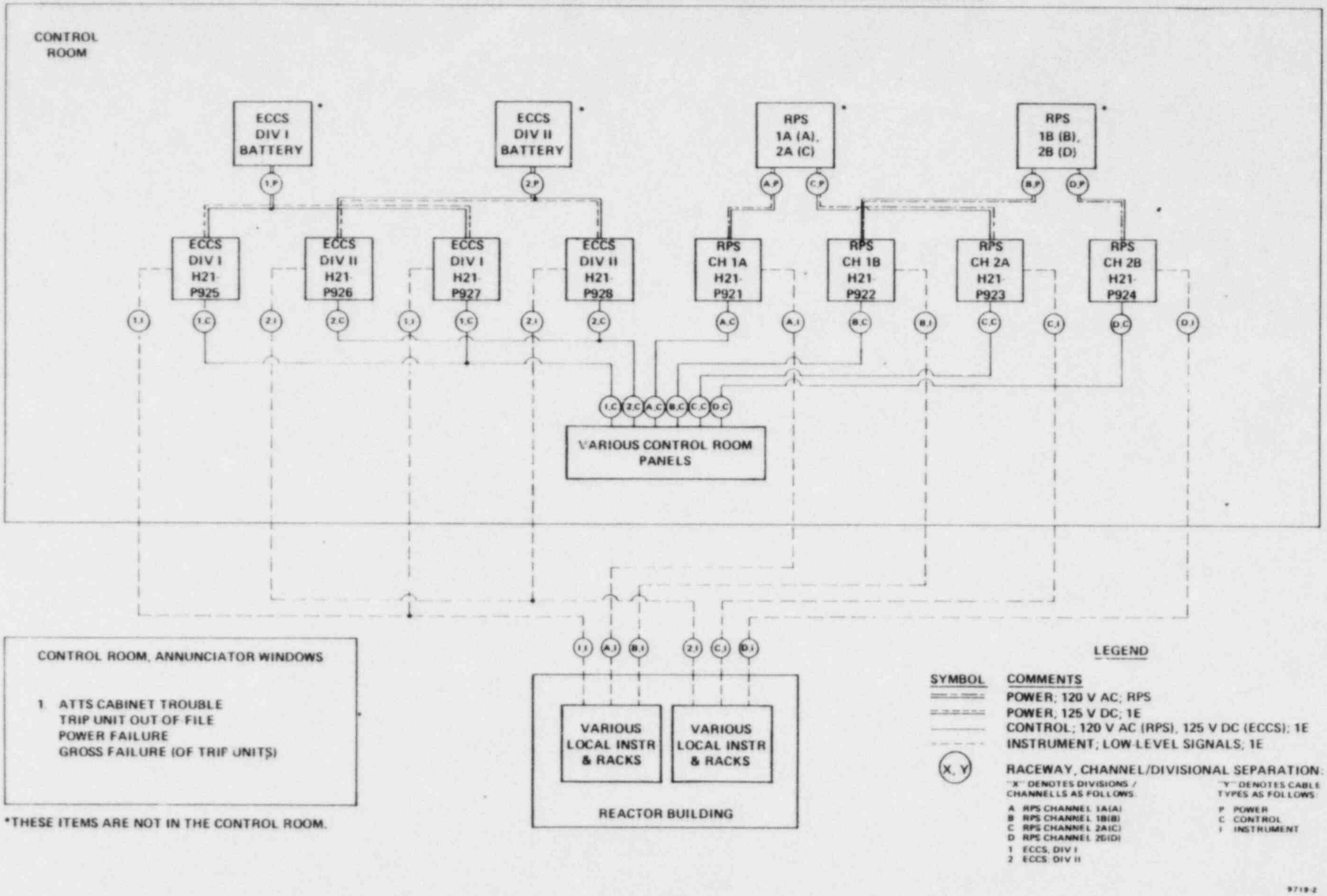


FIGURE 3.22 BASIC CABLE ARRANGEMENT AND SEPARATION LAYOUT FOR PLANT HATCH ATTS

3B. BASES FOR TECHNICAL SPECIFICATIONS REVISIONS FOR ATTS EQUIPMENT[a]

With the incorporation of ATTS into the HNP-1 design, two types of Technical Specifications revisions are desirable:

- Nomenclature changes
- Modifications to the surveillance frequency of ATTS equipment.

The bases for the Technical Specifications changes over and above these ATTS changes are included in Section IV.

3B.1 The bases for these changes are as follows:

3B.1.a Nomenclature Changes to the Technical Specifications

The installation of ATTS replaces mechanical switches with transmitters. In the past, the Technical Specifications identified the switches as such under the instrument description. Therefore, the Technical Specifications require a revision to reflect this change. Additional changes which are purely administrative in nature have been made to correct minor errors and to improve the readability of the Technical Specifications.

3B.1.b Modifications of the Surveillance Frequency

As evidenced by NEDO-21617-A, the NRC previously approved the following surveillance frequencies for ATTS equipment:

- Once per shift for channel check
- Once per month for channel functional test
- Once per operating cycle for channel calibration.

The revisions contained in the enclosed proposed changes to the Technical Specifications reflect the above surveillance frequencies.

Additional bases for the surveillance frequency revisions are contained within Chapter 6 of NEDE-22154-1 (contained in Reference 15).

3B.2 The proposed Technical Specifications revisions illustrated in this submittal are the revisions that will be incorporated into the Plant Hatch-Unit 1 system through the next refueling outage. GPC will apprise the NRC of the expected work scope to be completed and the desired implementation of the proposed Technical Specifications changes.

a. See Appendix 1 (page A1-2) for an 10 CFR 50.92 evaluation of the proposed changes to the Technical Specifications Surveillance requirements.

3C. SUMMARY

From the preceding discussions, it may be concluded that the proposed incorporation of the ATTS equipment into the Plant Hatch design and the proposed nomenclature and surveillance requirement changes to the Technical Specifications do not introduce an unreviewed safety question or a significant hazards consideration. These proposed changes take advantage of the sensor improvements for this new equipment.

IV. PROPOSED PLANT MODIFICATIONS TO BE INCORPORATED INTO THE ATTS DESIGN

4A. INTRODUCTION

Section IV provides the bases for the proposed Technical Specifications revisions, in addition to an overview of the evaluation performed to conclude that the proposed modifications constitute neither an unreviewed safety question, nor a significant hazards consideration. This section covers the Hatch 1 ATTS equipment items which are scheduled for installation during the 1984 refueling outage.

Within this section three values are discussed: the analytical limit, the trip setpoint/allowable value, and the trip setpoint. A discussion on these values and their determination is presented below.

4A.1 Setpoint Methodolgy

The methodology which was used to generate the setpoints is detailed in Attachment 3 of Reference 16.

4A.1.a Analytical Limits

The analytical limits are the values used as inputs to the safety analysis in the FSAR. For Plant Hatch, the analytical limits were selected to prevent violation of the applicable safety limits. For example, the analytical limit for the level 1 reactor water level trip was selected to prevent fuel cladding temperatures in excess of the peak value (2200°F) used in the Plant Hatch Appendix K LOCA analyses.

In some cases values were not used directly in the FSAR analysis. In those cases where an analytical limit was not available, engineering judgement or historical data was justified and used.

Unless otherwise noted, the analytical limits used in the setpoint calculations for this submittal were the original analytical limits used in the HNP Safety Analysis. For those that were changed, a safety evaluation is provided that justifies the change to that analytical limit. In no case with these new limits do the FSAR analyzed transients or accidents exceed the safety limits which are specified in the Plant Hatch Technical Specifications.

The conservatisms in the Plant Hatch design basis computer codes were not used in place of the analytical limit for the starting value of the calculations.

4A.1.b Allowable Value and Trip Setpoint Determinations

The allowable value was obtainined by either adding or subtracting (whichever was conservative) the loop accuracy from the analytical limit. The loop accuracy was obtained by taking the square root-of-the-sum-of-the squares of the transmitter accuracy, the trip unit accuracy, and the calibration accuracy. The trip setpoint was calculated by adding or subtracting (whichever was used to obtain the allowable value) the loop drift and the leave-alone range from the allowable value.

Each of these terms is a function of other parameters; for instance, the transmitter accuracy reflects transmitter performance with regard to the transmitter temperature specifications, power supply specifications, and static pressure specifications. Trip unit accuracy is basic reference accuracy. Calibration accuracy consists of the accuracy of applying pressure to the transmitter and measuring its electrical output error band. Thus, trip unit calibration accuracy is a function of the ATTS calibration units and the readout used to adjust the trip setpoints. What we refer to as loop accuracy is developed by taking the square root-of-the-sum-of-the squares of all the terms. These parameters envelope the Plant Hatch, Unit 1 requirements.

The transmitter, trip unit, and calibration accuracies are all treated as independent variables between the analytical limit and allowable value. The transmitter and trip unit drifts were treated as independent variables between the allowable value and trip setpoint. The total loop accuracies and the total loop drifts were directly added to obtain the trip setpoint and were, therefore, treated as dependent variables.

An additional variable called the leave-alone band was added (treated as a dependent variable) between the allowable value and trip setpoint. This band is set at ± 0.25-percent of the trip unit range and allows a range of values that the trip unit may vary. A setpoint adjustment is not required when the trip unit setting is within this ± 0.25-percent range. If the trip unit is out of the leave-alone band on a monthly calibration functional test, the operator resets the trip unit trip setpoint within the 0.25-percent range. Currently, if the trip unit setting is more than ± 0.60-percent (sum of leave-alone range + trip unit drift) from the specified setpoint, a deficiency report will be generated internally at GPC Plant Hatch.

The only value extrapolated was setpoint drift. In many cases the transmitter manufacturer's specifications only provided drift values for 6- or 12-month intervals. These values were extrapolated linearly to provide 18- and 24-month drift values for use in the Plant Hatch setpoint calculations. Ongoing vendor test programs demonstrate that linear extrapolation is a conservative approach.

Drift of the trip units will be monitored on a monthly basis, and drift of the transmitters will be monitored on an operating cycle basis using plant procedures. After two operating cycles, GPC will evaluate the performance of these trip units and transmitters against the manufacturer's published specifications. At that time, if necessary, GPC will propose modifications to the surveillance frequencies specified in the Unit 1 Technical Specifications based upon this performance.

4A.1.c Harsh Environment Considerations

The temperature effects for a harsh environment were explicitly used as one of the variables to determine transmitter accuracy for each loop. The data used were obtained directly from the transmitter performance specifications. No extrapolations were required. The manufacturer's performance specifications envelope the Plant Hatch calculated harsh environment profiles.

The two areas explicitly considered in the harsh environment effects were radiation and temperature compensation. These were considered as independent effects. The reasoning that they are independent effects is that temperature peaks relatively early in a LOCA event while significant radiation integrated doses occur later. As a result of a GE evaluation for Barton transmitters, it was determined that radiation effects were not significant in the setpoint calculations. Therefore, the setpoint calculations did not explicitly consider radiation as a parameter. SCS performed an evaluation which allowed exclusion of the radiation effect also for those functions where Rosemount transmitters are to be installed.

Humidity was not an explicit parameter in the setpoint calculations. The testing program for the transmitters included exposure to a steam environment during the DBE/post-DBE testing phases. Therefore, the effects of humidity are accounted for in the temperature compensation factor.

4A.1.d Human Factors Consideratons

No component of error for the man-to-machine interface was included in the setpoint calculations; however, there is a requirement that calibration be performed with instruments of 1/4-percent or better accuracy. This value was assumed in the setpoint calculations.

During monthly channel functional tests, the trip setpoint milliampere value is read directly from the calibration unit. The calibration unit locks in the trip setpoint value and presents a digital display. During channel calibration, the readings are taken with a digital voltmeter. At the calibration checkpoints, sufficient stability of the digital readout is achieved to assure that the human ability to read the display presents insigificant errors in the overall results of the setpoints calculations.

4B. SAFETY EVALUATION REPORT

4B.1 Low Low Set Logic Design Modification (B21-N620A,B,C,D; B21-N621A,B,C,D; B21-N622A,B,C,D)

The concept and justification for the low low set (LLS) logic to be incorporated into the HNP-1 design are detailed in NEDE-22223 and NEDE-22224 which are contained within Appendices 1 and 2 of Reference 1. Reference 1, the Hatch Nuclear Plant-Unit 2 (HNP-2) low low set submittal, was approved by the NRC on June 29, 1983.

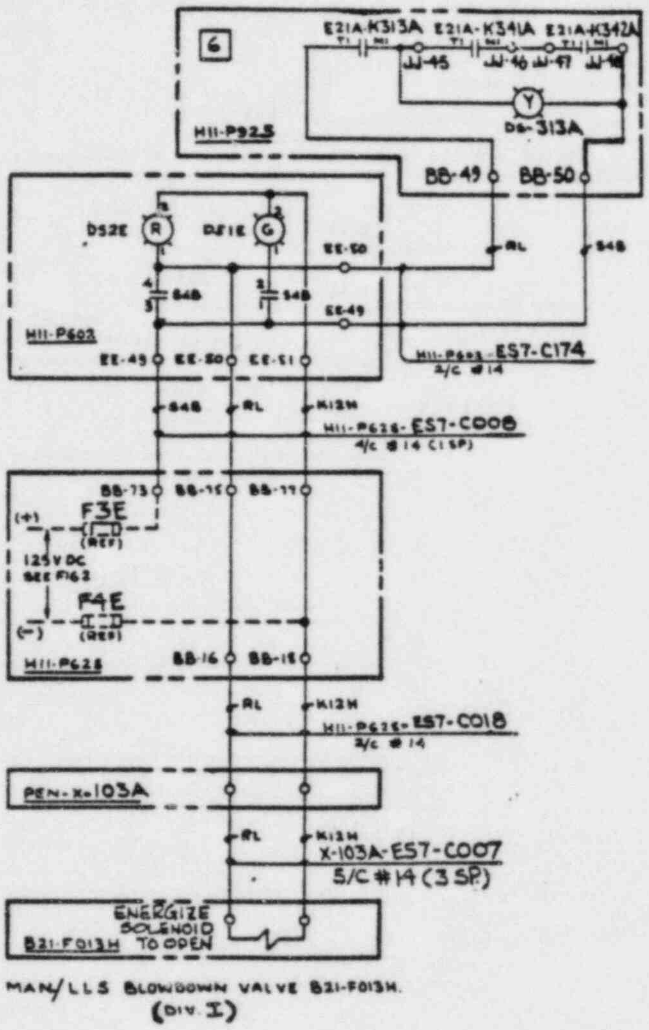
The purpose of the LLS relief logic is to mitigate the induced loads of subsequent safety/relief valve (S/RV) actuations as identified in NUREG-0661. The LLS relief logic automatically arms the designated LLS S/RVs at their LLS setpoints when any S/RV opens initially and when, concurrently, the reactor vessel steam dome pressure exceeds the scram setpoint. After arming, the reactor vessel steam dome pressure instrumentation controls the solenoid valves so that the LLS S/RVs open and close at their assigned setpoints. Technical Specifications revisions are required to accurately reflect the newly designated safety function of the selected S/RVs. However, as justified in Appendices 1 and 2 of reference 1, this modification constitutes neither an unreviewed safety question, nor a significant hazards consideration. Appendix 1 (page A1-3) of this document provides the results of the significant hazards review.

The proposed limiting condition for operation (LCO) requirements were developed taking into consideration reference 13 which is currently under NRC review. The proposed surveillance requirements were developed from the ATTS requirements since the LLS instrumentation is being incorporated into the plant design as part of this system. The proposed surveillance requirements for ATTS are justified in Section III of this document.

The proposed LCO requirements are less restrictive than the LCO requirements specified in Reference 13, which assume the presence of one tailpipe pressure switch per S/RV. The new HNP-1 design incorporates two independent tailpipe pressure switches (designed to meet single-failure criteria) per S/RV. Should one tailpipe pressure switch become inoperable on a low setpoint (1080 psig) S/RV, there is a second switch to support the arming of the LLS logic should that S/RV open. If the redundant tailpipe pressure switch also fails, there are three additional S/RVs with 1080-psig setpoints, at least one of which is assumed to open with the opening of the S/RV with the failed tailpipe pressure switches. Should any one (or more) S/RV open and should any one tailpipe pressure switch sense the opening of the S/RV, the tailpipe pressure switches would have served their function in regard to the LLS logic operation. Should an S/RV with two failed switches open and no other S/RV opens concurrently, the LLS relief logic can be defeated. Figures 4.1 through 4.10 provide the engineering documents which are relevant to understanding the proposed LLS logic design modification for Unit 1.

A reliability analysis was performed to predict the probability of a defeat of LLS logic to mitigate the load cases C3.2 and C3.3 (NEDC-24346). This analysis assumed that one of the two pressure switches of each S/RV failed and only one S/RV responded to mitigate these load cases. (There are only a small number of events under load cases C3.2 and C3.3 where the potential exists for only one S/RV opening. However, to be conservative it was assumed that the probability of this occurrence was 1. If more than one S/RV did open, additional pressure switches would be available to arm the LLS logic.) Using WASH-1400 failure rates, it was predicted that the probability of LLS logic being defeated upon demand would be 1.97×10^{-7} assuming all pressure switches are operable at startup after refueling. Therefore, the proposed LCO requirements with one operable tailpipe pressure switch per S/RV are justified.

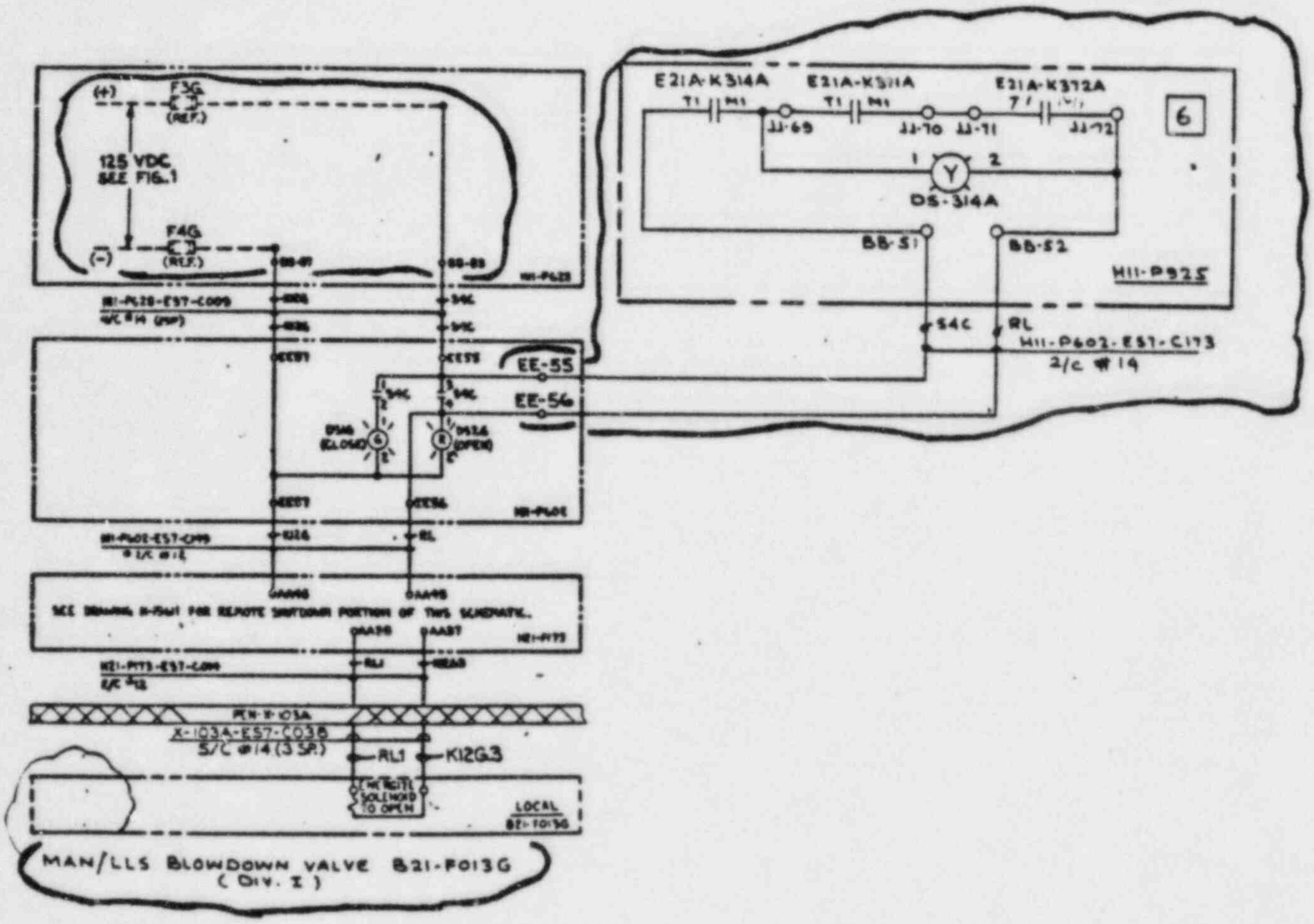
The proposed setpoints/allowable values were developed using the criteria of Regulatory Guide 1.105, taking into consideration the design basis of the system.



LOW LOW SET VALVE B21-F013H
ELEMENTARY DRAWING
REVISION TO H-17755

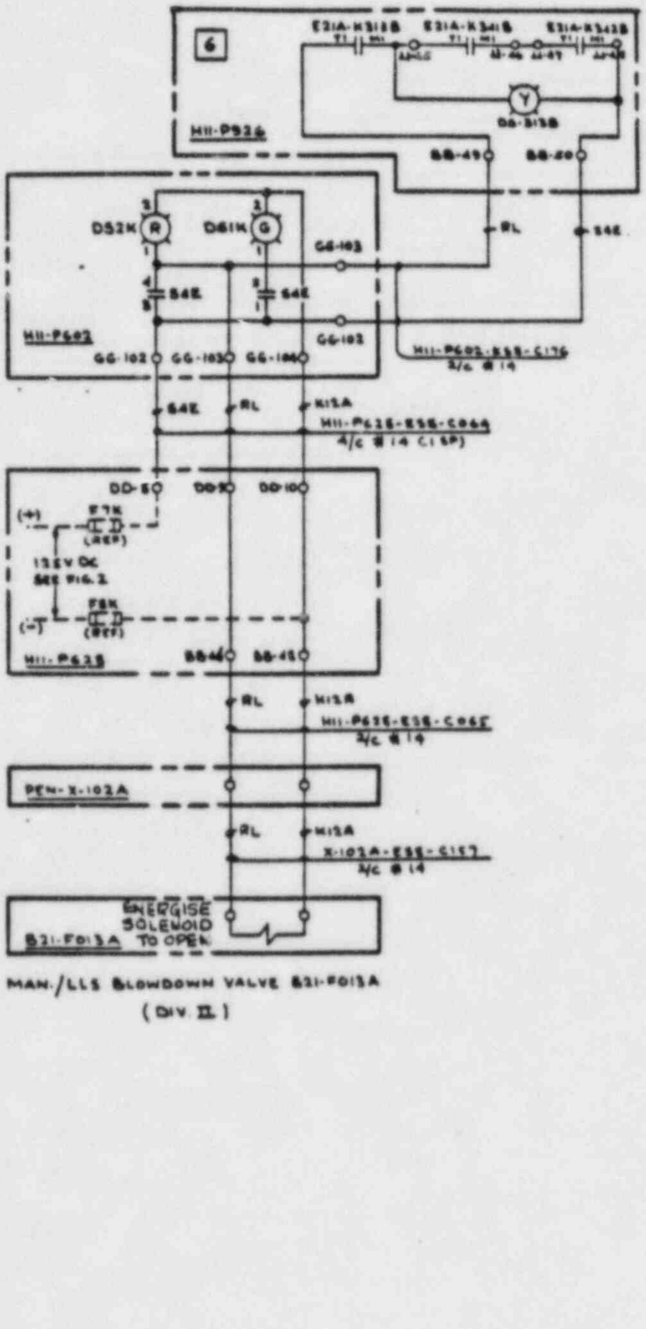
FIGURE 4.1

3605-0



LOW LOW SET VALVE B21-F013G
ELEMENTARY DRAWING REVISION
TO H-17755

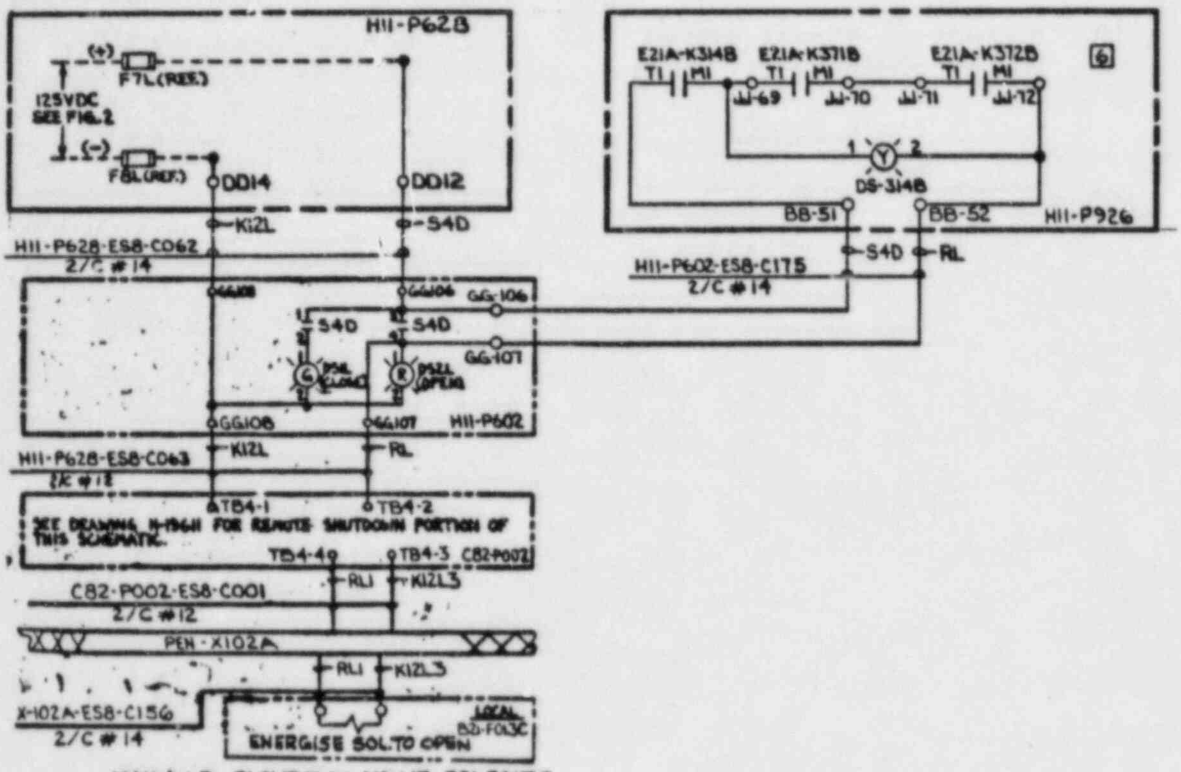
FIGURE 4.2



LOW LOW SET VALVE B21-F013A, ELEMENTARY DRAWING REVISION TO H-17755

FIGURE 4.3

3605-0

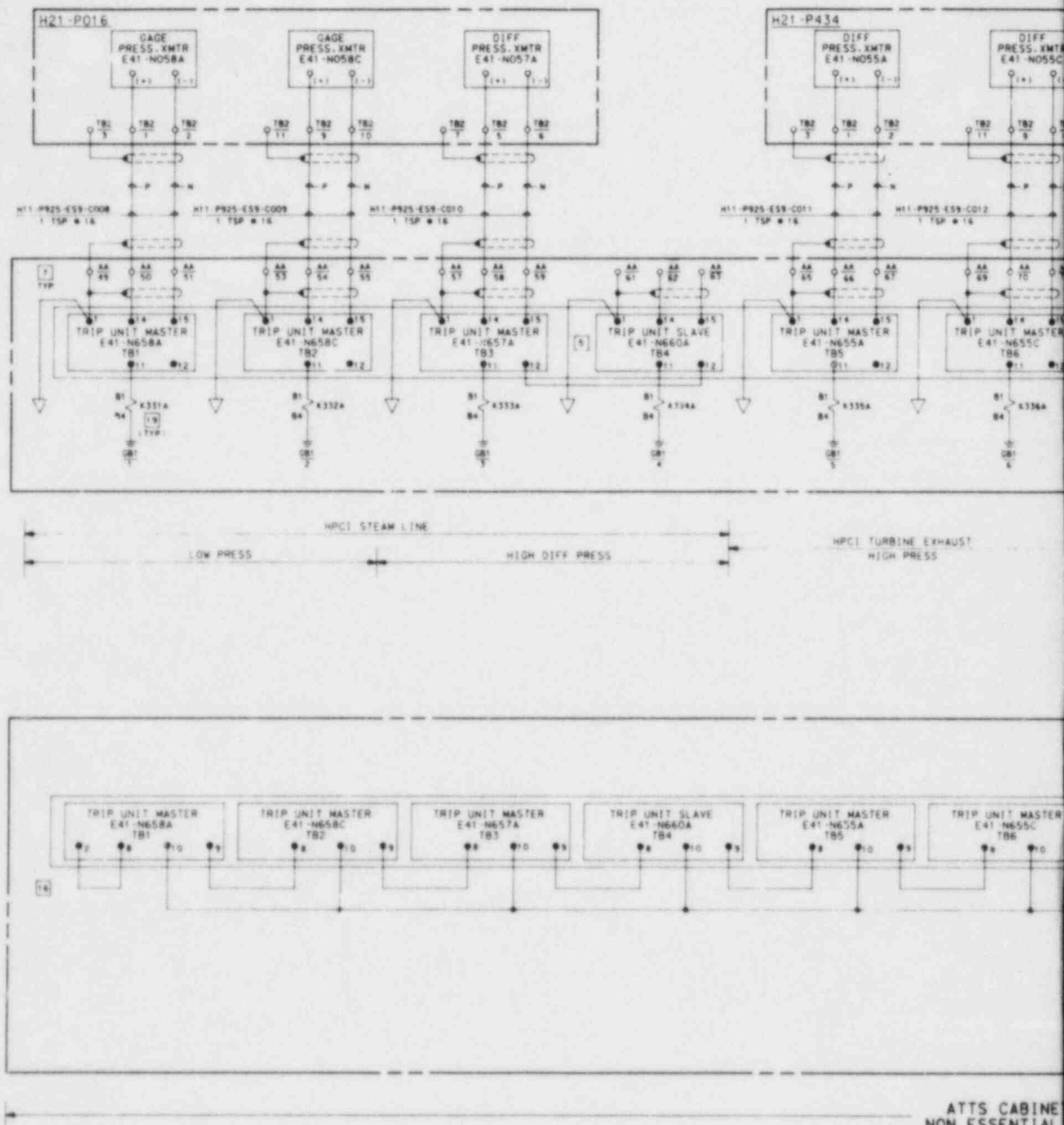


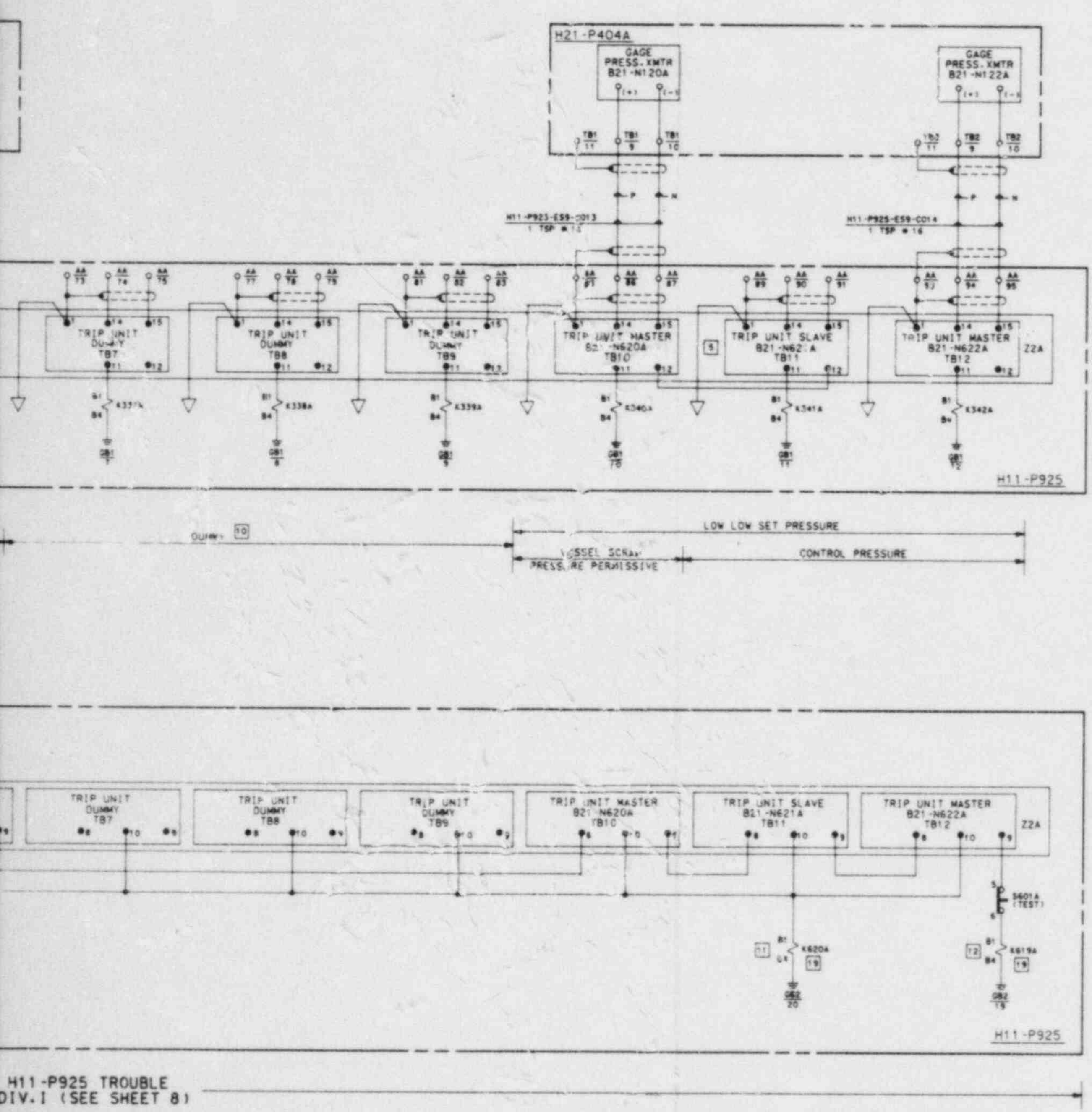
MAN/LLS BLOWDOWN VALVE B21-F013C (DIV. II)

LOW LOW SET VALVE B21-F013C ELEMENTARY DRAWING REVISION TO H-17755

FIGURE 4.4

3605-0


H21-P016
GAGE PRESS. XMTR E41-N058A
GAGE PRESS. XMTR E41-N058C
DIFF PRESS. XMTR E41-N057A
H21-P434
DIFF PRESS. XMTR E41-N055A
TRIP UNIT MASTER E41-N658A TB1
TRIP UNIT MASTER E41-N658C TB2
TRIP UNIT MASTER E41-N657A TB3
TRIP UNIT SLAVE E41-N660A TB4
TRIP UNIT MASTER E41-N655A TB5
TRIP UNIT MASTER E41-N655C TB6
HPCI STEAM LINE
LOW PRESS
HIGH DIFF PRESS
HPCI TURBINE EXHAUST HIGH PRESS
ATTS CABINE
NON ESSENTIAL



TI APERTURE CARD

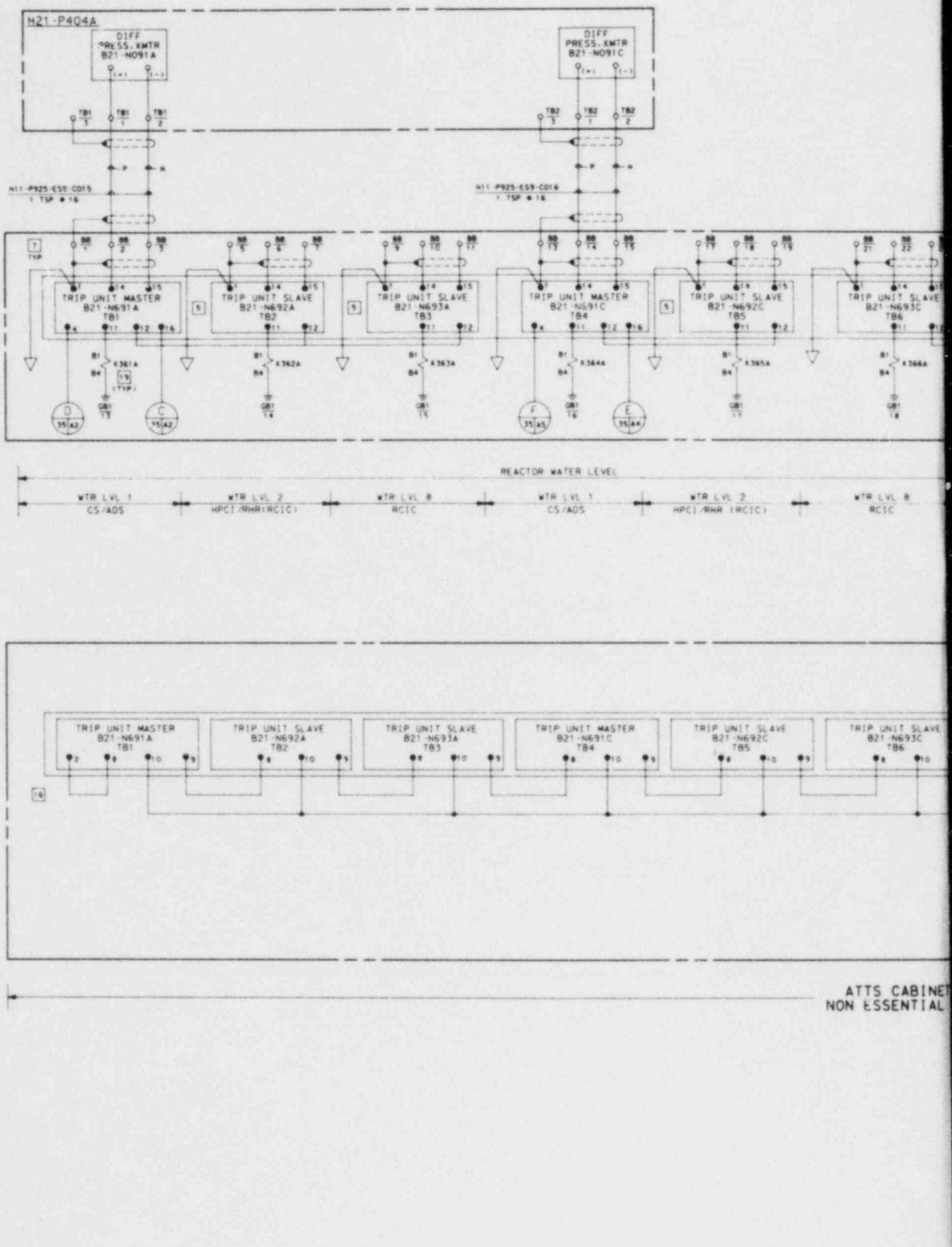
Also Available On Aperture Card

H-19822 REV. A

ATTS ELEMENTARY DIAGRAM

FIGURE 4.5

8409120096-01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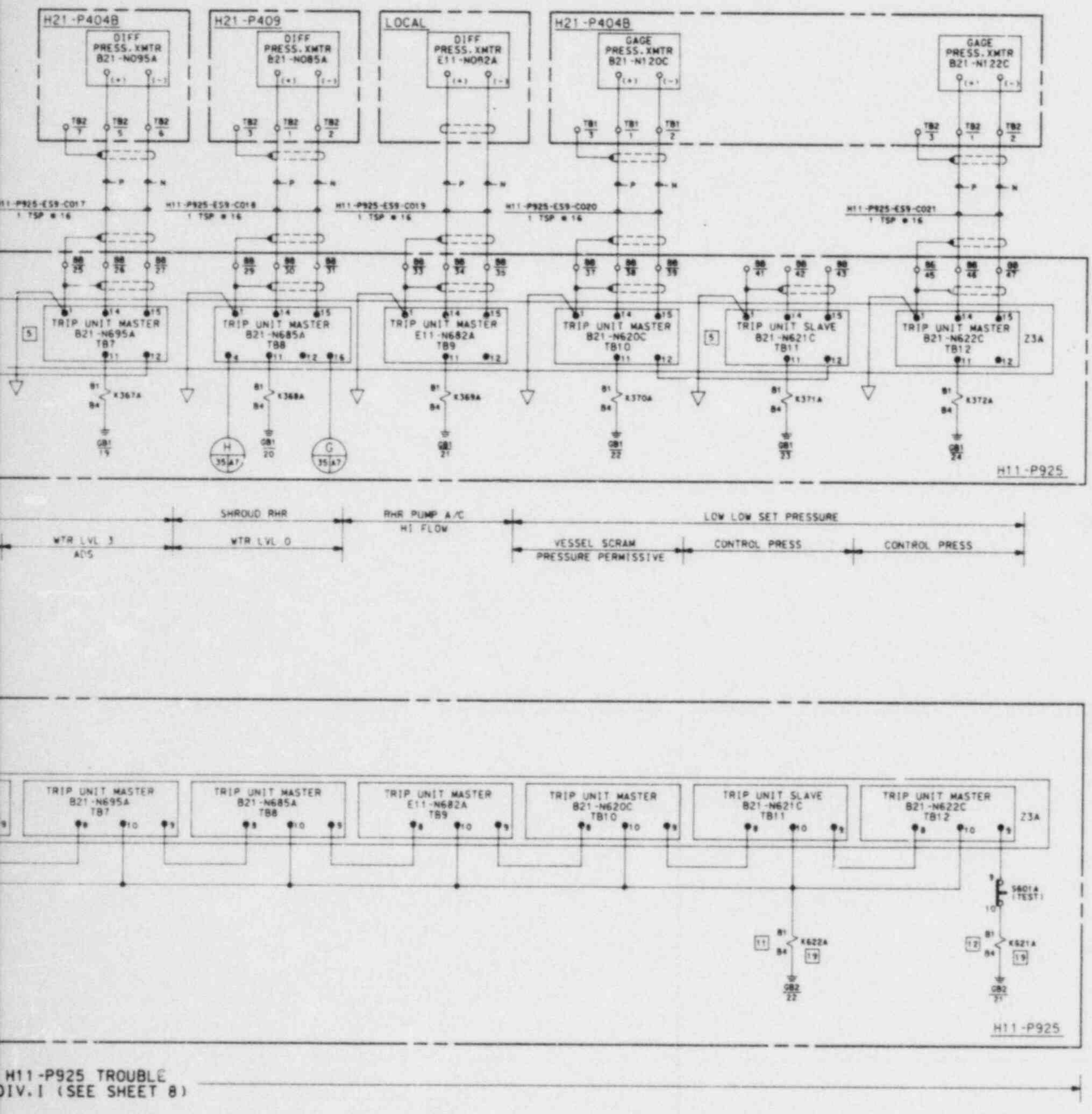
DIFF PRESS. XMTR B21-N091C
H11-P925-ES8-C015
1 TSP # 16
H11-P925-ES9-C016
1 TSP # 16
TRIP UNIT MASTER B21-N691A TB1
TRIP UNIT SLAVE B21-N692A TB2
TRIP UNIT SLAVE B21-N693A TB3
TRIP UNIT MASTER B21-N691C TB4
TRIP UNIT SLAVE B21-N692C TB5
TRIP UNIT SLAVE B21-N693C TB6
K361A
K362A
K363A
K364A
K365A
K366A
REACTOR WATER LEVEL
WTR LVL 1
CS/ADS
WTR LVL 2
HPCI/RHR(RCIC)
WTR LVL 8
RCIC
WTR LVL 1
CS/ADS
WTR LVL 2
HPCI/RHR (RCIC)
WTR LVL 8
RCIC
TRIP UNIT MASTER B21-N691A TB1
TRIP UNIT SLAVE B21-N692A TB2
TRIP UNIT SLAVE B21-N693A TB3
TRIP UNIT MASTER B21-N691C TB4
TRIP UNIT SLAVE B21-N692C TB5
TRIP UNIT SLAVE B21-N693C TB6
ATTS CABINET
NON ESSENTIAL

3605-G



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APERTURE
CARD

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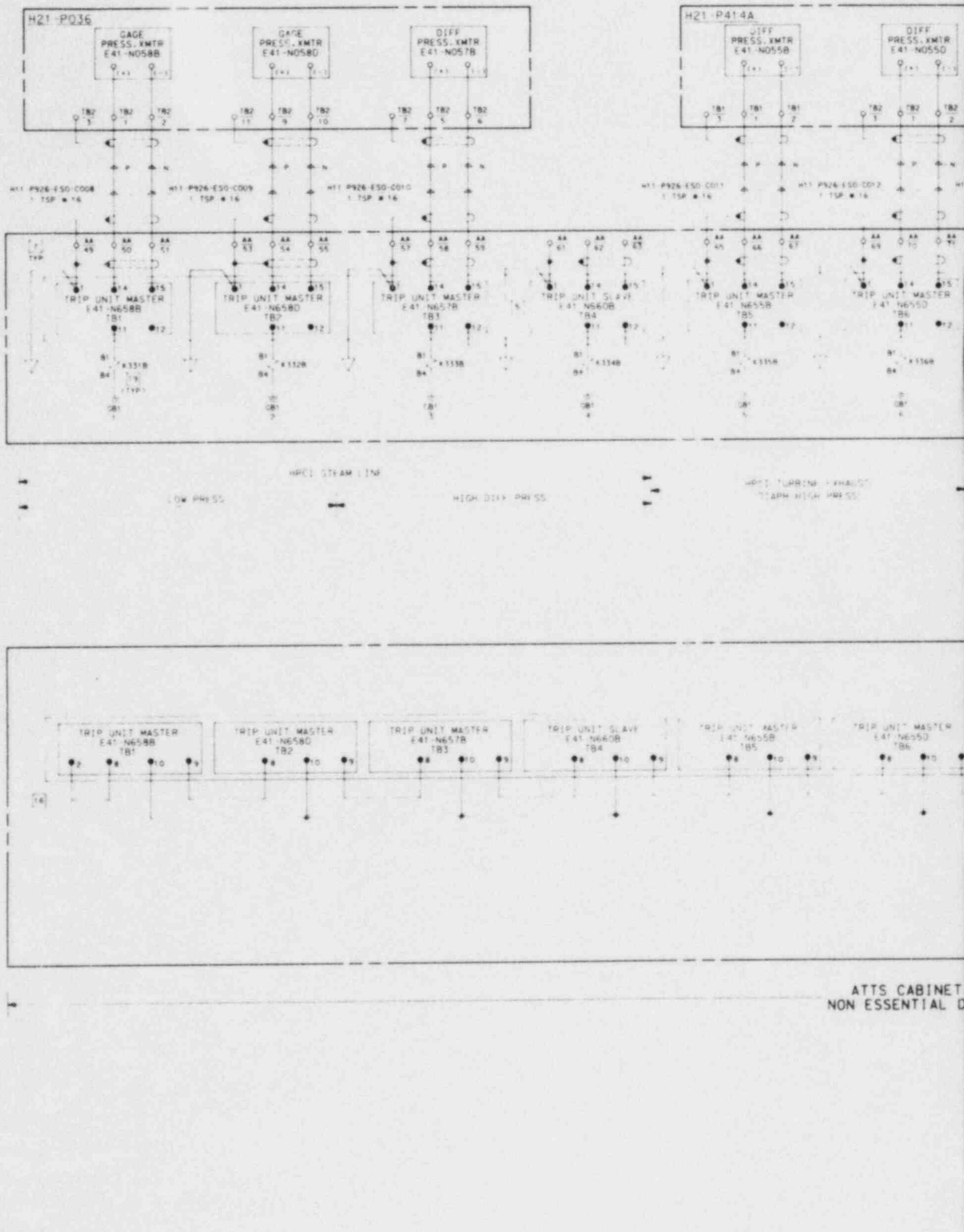
Aperture Card

H-19823 REV. A

ATTS ELEMENTARY
DIAGRAM

FIGURE 4.6

8409120096-02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GAGE PRESS. XMTR E41-N058D
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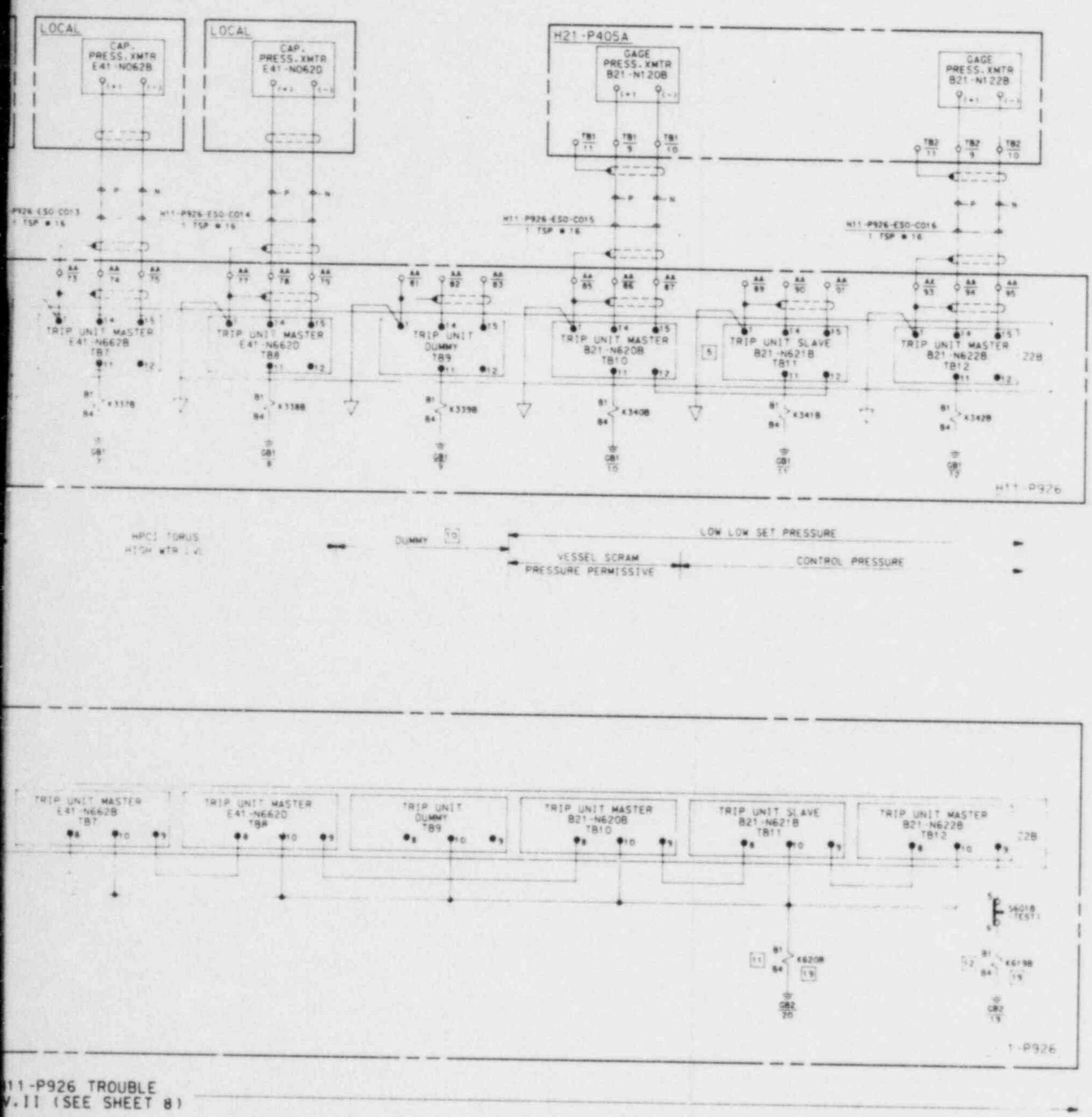
H21-P414A
DIFF PRESS. XMTR E41-N055B
DIFF PRESS. XMTR E41-N055D
TRIP UNIT MASTER E41-N658B TB1
TRIP UNIT MASTER E41-N658D TB2
TRIP UNIT MASTER E41-N657B TB3
TRIP UNIT SLAVE E41-N660B TB4
TRIP UNIT MASTER E41-N655B TB5
TRIP UNIT MASTER E41-N655D TB6
HPCI STEAM LINE
LOW PRESS
HIGH DIFF PRESS
ATTS CABINET
NON ESSENTIAL D



Also Available On
Aperture Card

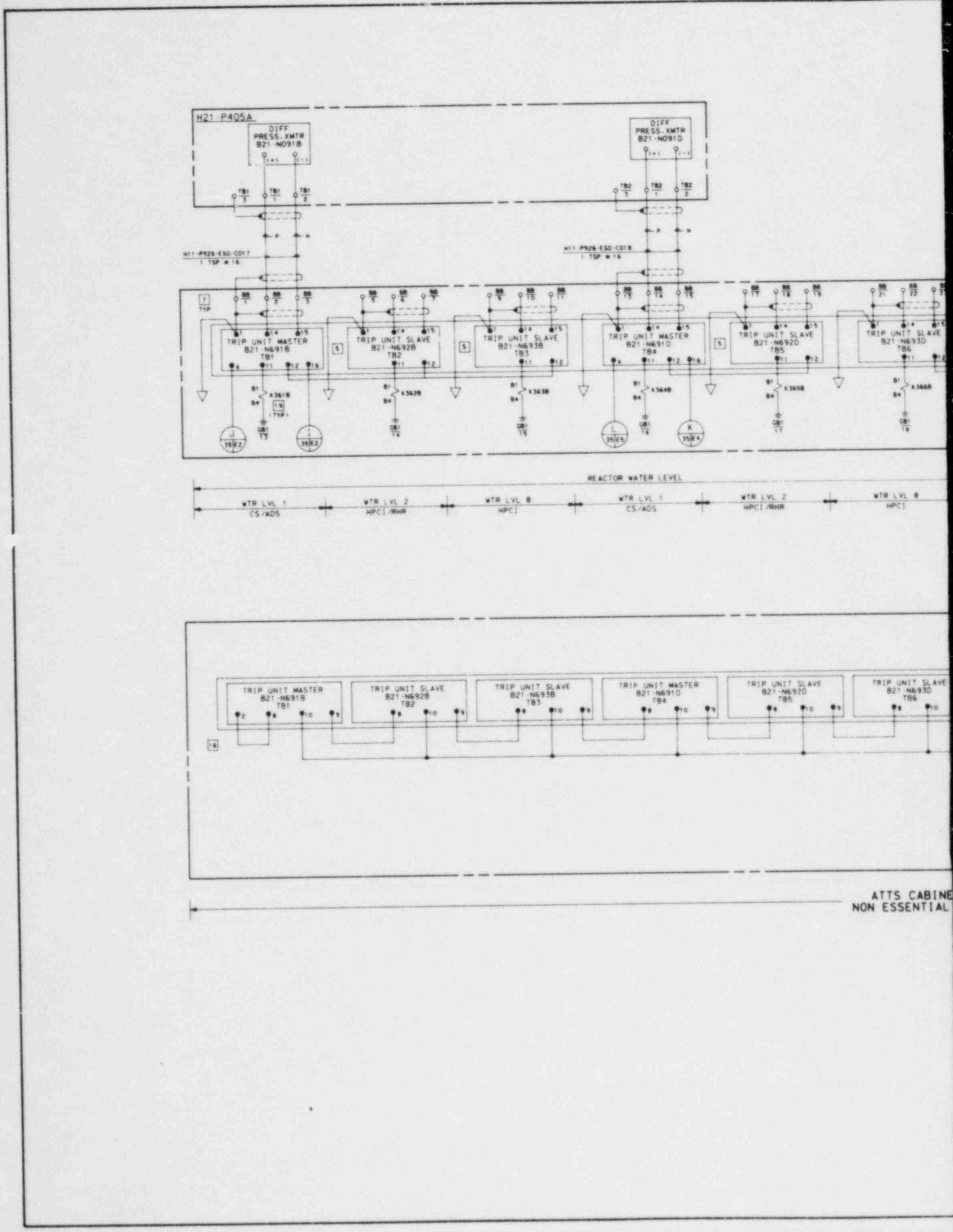
TI
APERTURE
CARD

H-19825 REV. A

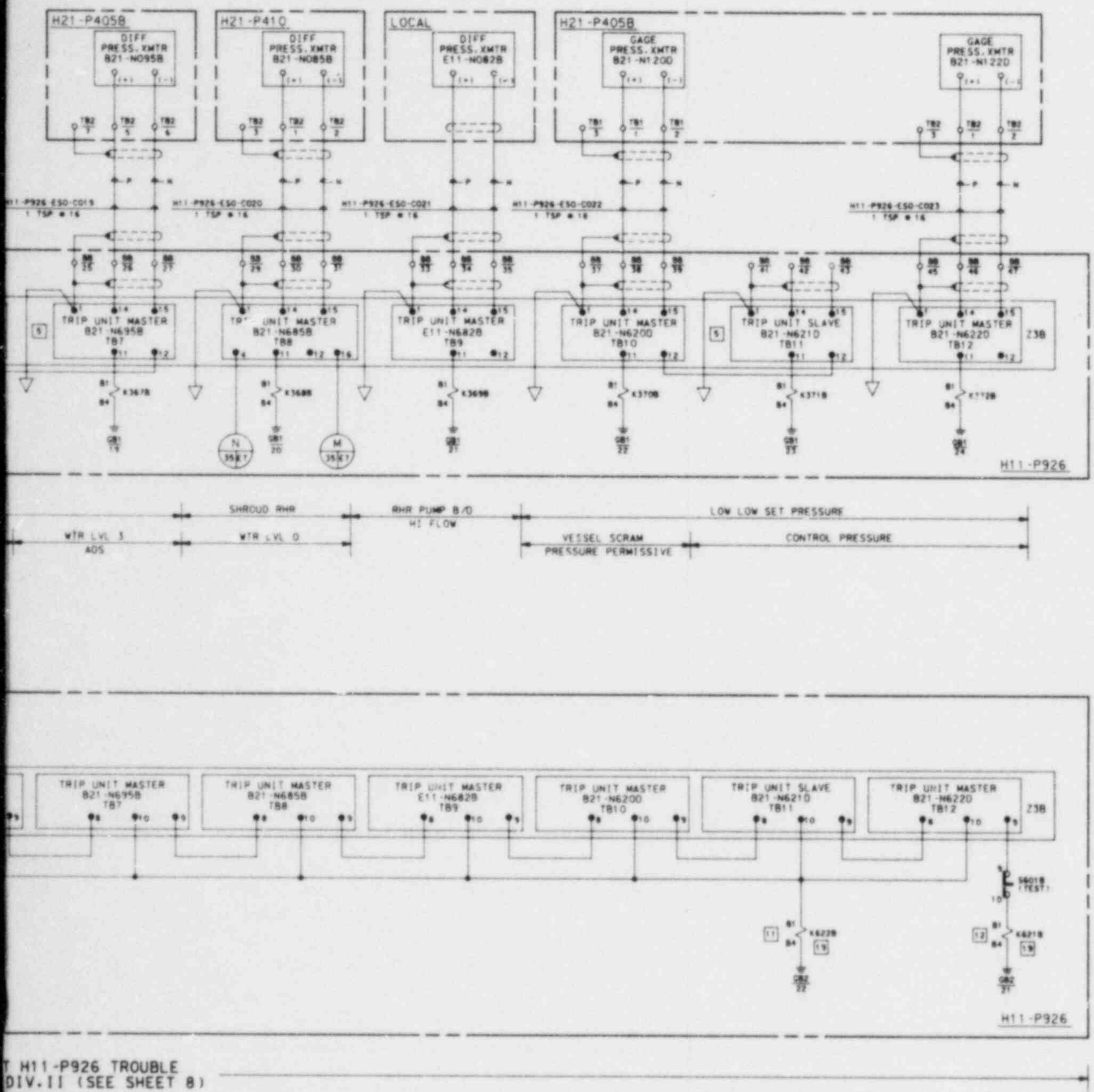
ATTS ELEMENTARY
DIAGRAM

FIGURE 4.7

8409120096-D?


H21-P405A
DIFF PRESS. XMTR B21-N091B
DIFF PRESS. XMTR B21-N091D
H11-P926-ESD-C017
1 TSP # 16
H11-P926-ESD-C018
1 TSP # 16
TRIP UNIT MASTER B21-N691B TB1
TRIP UNIT SLAVE B21-N692B TB2
TRIP UNIT SLAVE B21-N693B TB3
TRIP UNIT MASTER B21-N691D TB4
TRIP UNIT SLAVE B21-N692D TB5
TRIP UNIT SLAVE B21-N693D TB6
K361B
K362B
K363B
K364B
K365B
K366B
REACTOR WATER LEVEL
WTR LVL 1
CS/ADS
WTR LVL 2
HPCI/RHR
WTR LVL 8
HPCI
WTR LVL 1
CS/ADS
WTR LVL 2
HPCI/RHR
WTR LVL 8
HPCI
ATTS CABINE
NON ESSENTIAL

3605-0



TI APERTURE CARD

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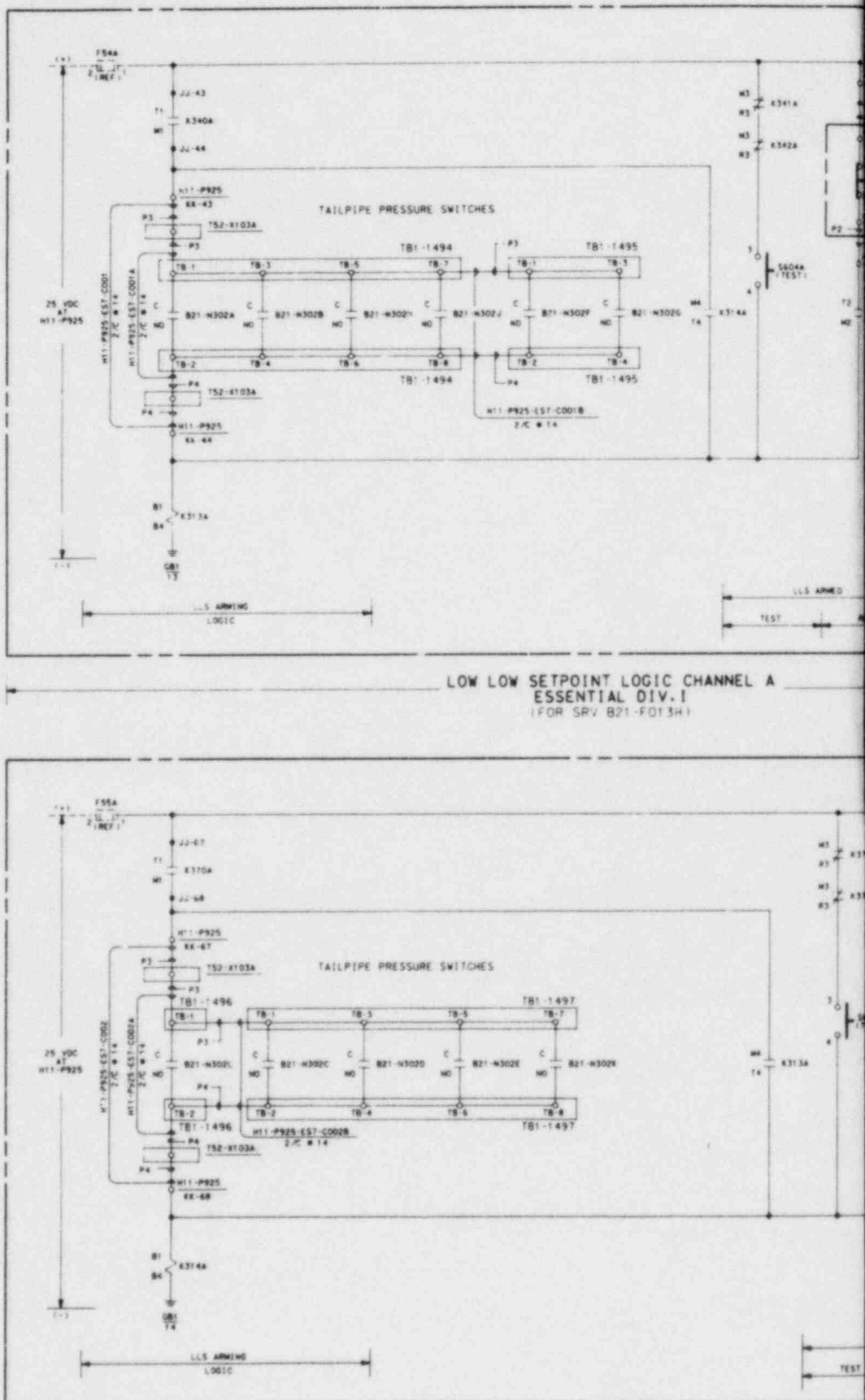
H-19826 REV. A

ATTS ELEMENTARY DIAGRAM

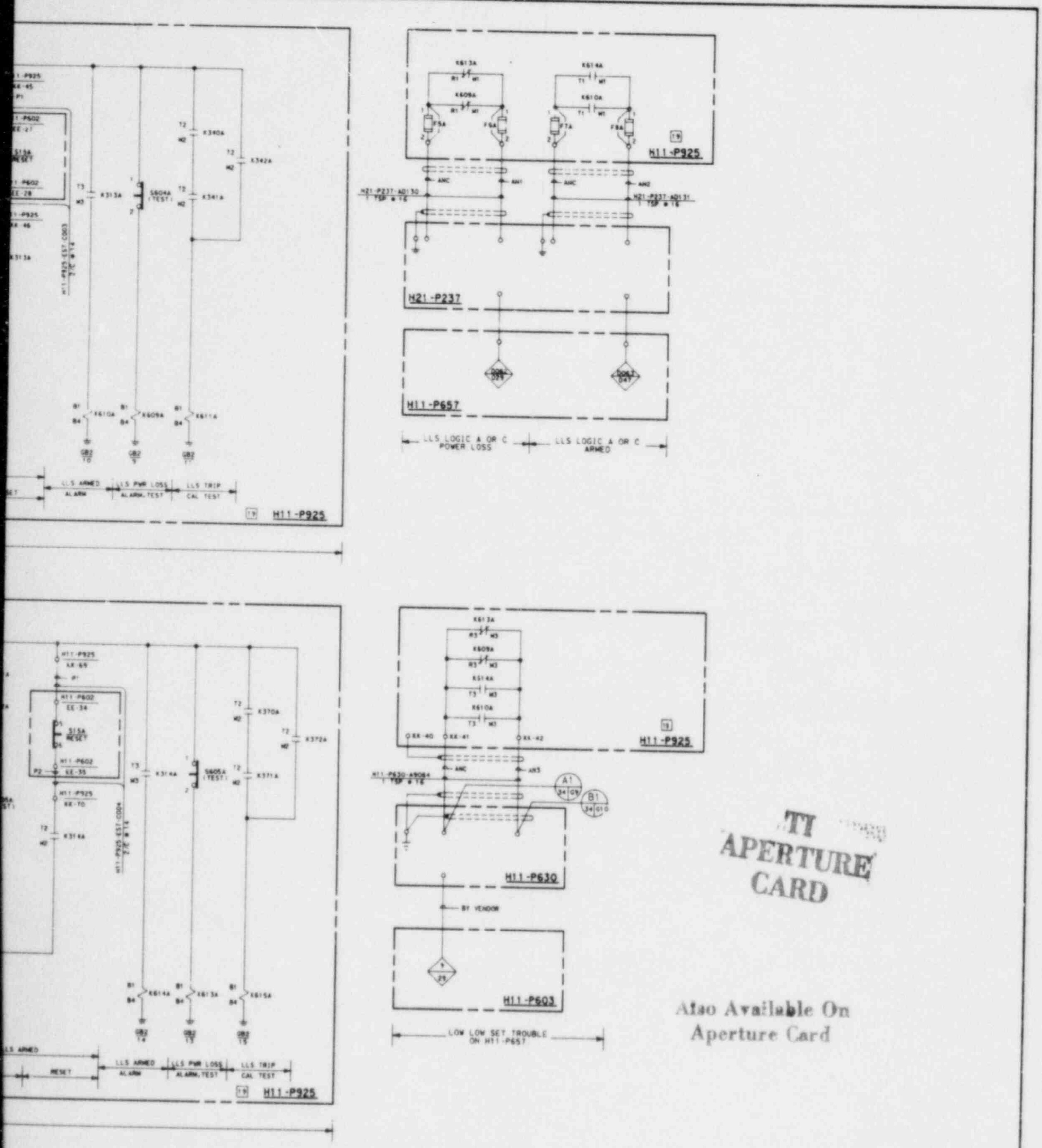
FIGURE 4.8

8409120096-04



LOW LOW SETPOINT LOGIC CHANNEL A
ESSENTIAL DIV. I
(FOR SRV B21-F013H)

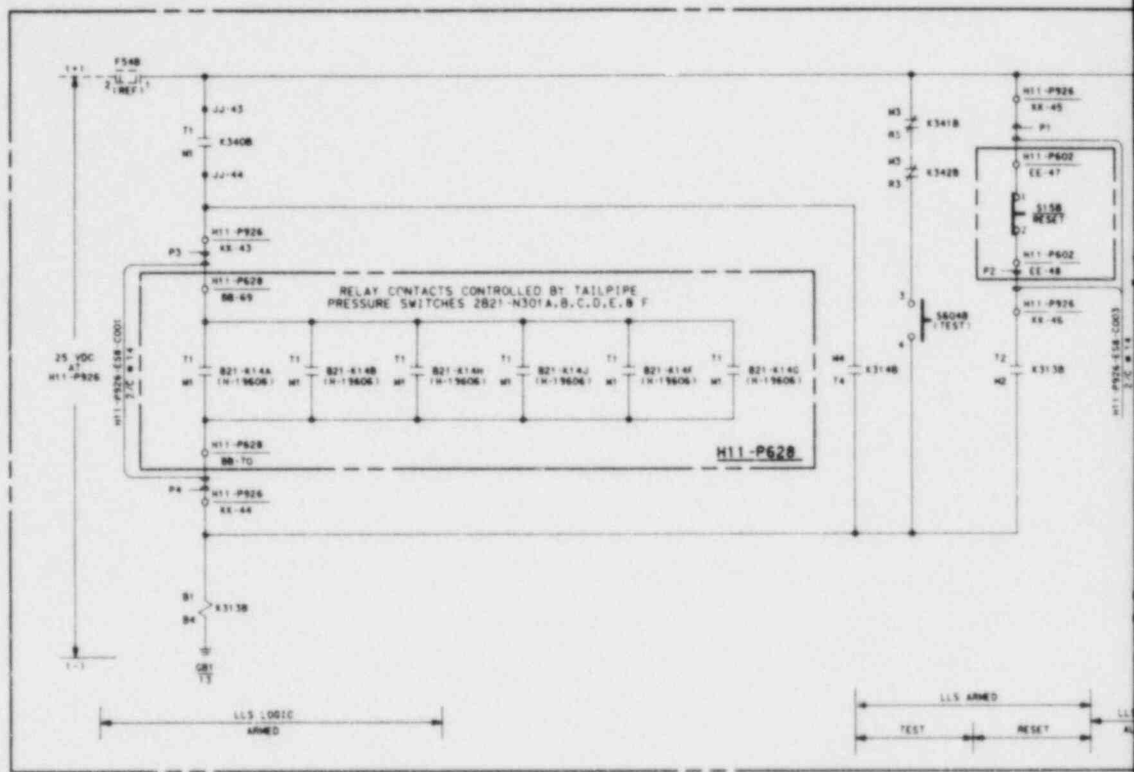
LOW LOW SETPOINT LOGIC CHANNEL C
ESSENTIAL DIV. I
(FOR SRV B21-F013G)



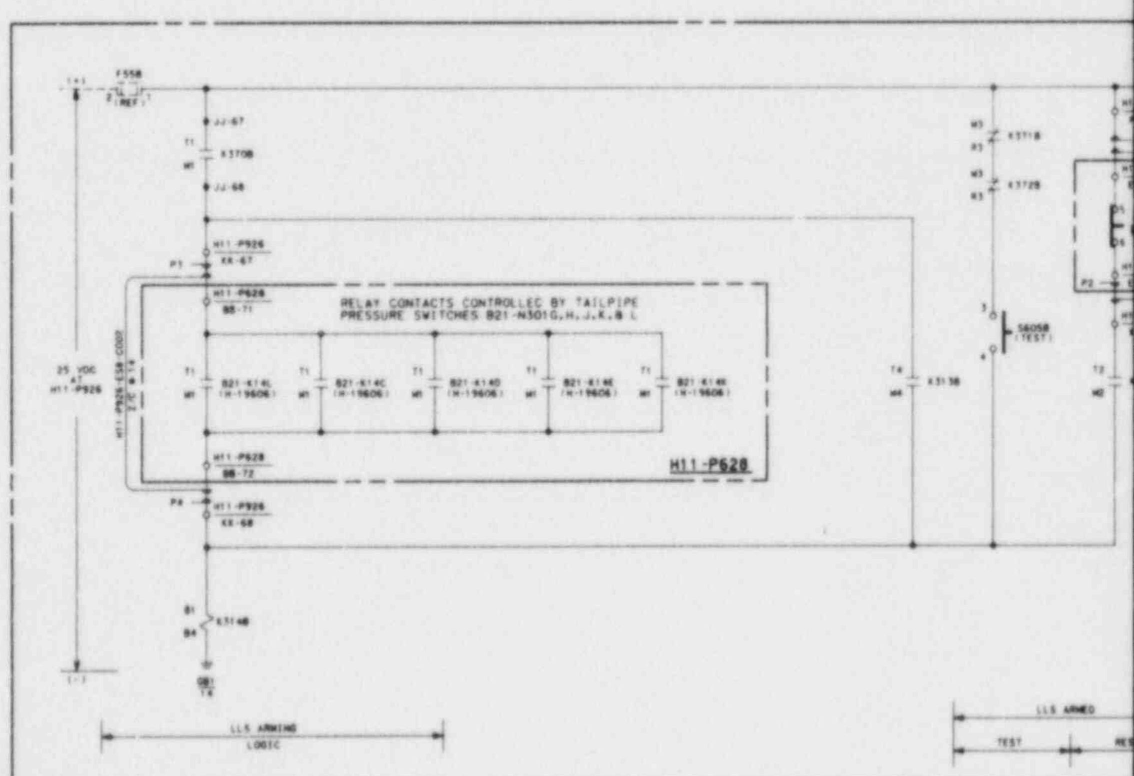
H-19833 REV. A

ATTS ELEMENTARY DIAGRAM

FIGURE 4.9

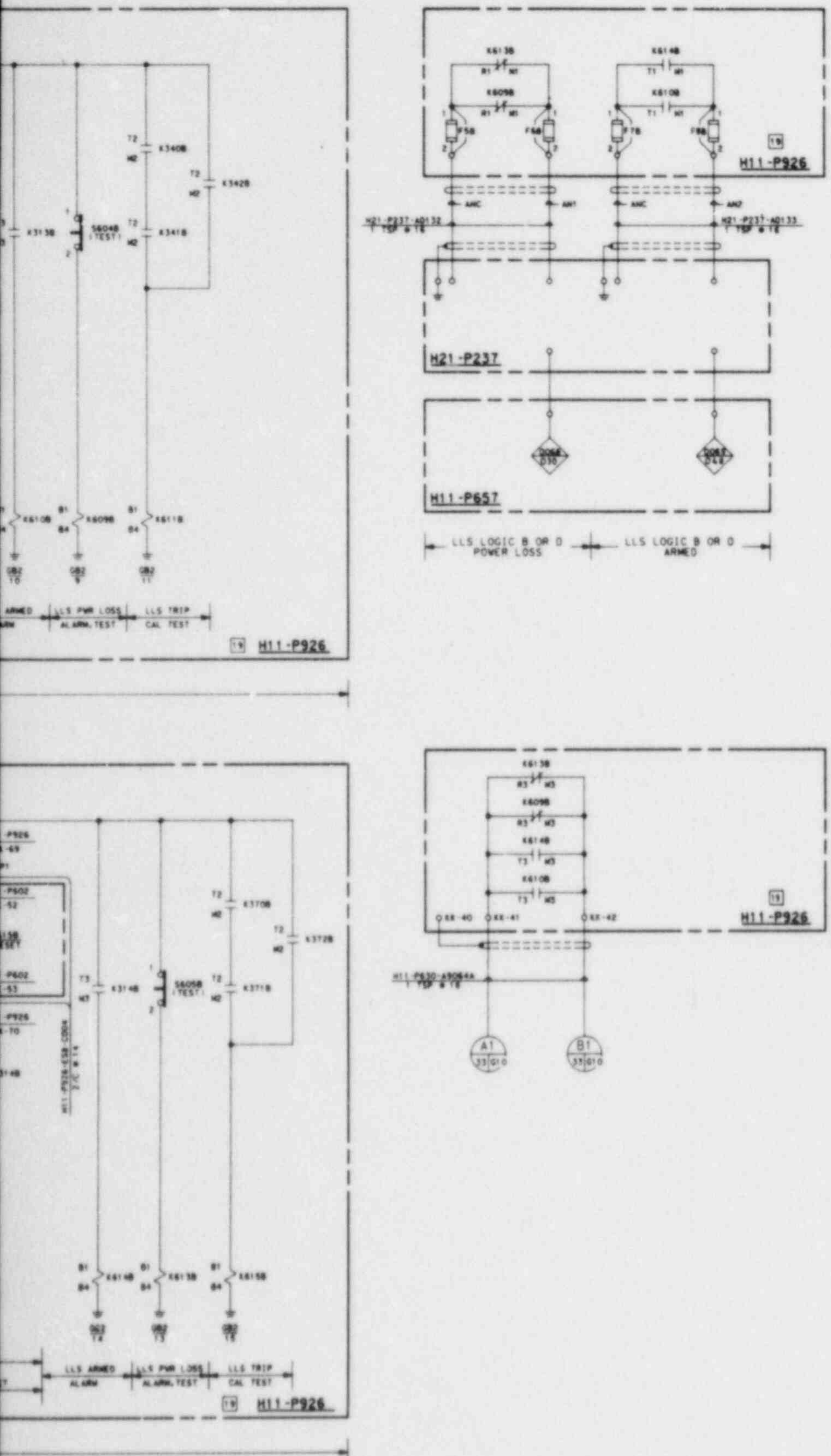


LOW LOW SETPOINT LOGIC CHANNEL B
ESSENTIAL DIV.II
(FOR SRV B21-F013A)



LOW LOW SETPOINT LOGIC CHANNEL D
ESSENTIAL DIV.II
(FOR SRV B21-F013C)

3605-0



H-19834 REV. A

ATTS ELEMENTARY DIAGRAM
FIGURE 4.10

4B.2 Lowered Main Steam Isolation Valve (MSIV) Water Level Trip Setpoint Modification (B21-N681A,B,C,D)

The justification for the lowering of the MSIV water level trip setpoint from level 2 to level 1 is detailed in the NEDE-22223 and NEDE-22224 (Appendices 1 and 2 of Reference 1, the HNP-2 MSIV Lowered Water Level submittal approved by the NRC on June 29, 1983).

The lowering of the MSIV water level trip setpoint is an additional means of mitigating the induced loads of subsequent S/RV actuations. A delayed MSIV isolation allows more steam to be released from the reactor prior to an S/RV actuation. The subsequent pressurization rate after MSIV isolation is also reduced because of the lower decay heat rate at this later time.

This modification is also being implemented in response to the generic NRC evaluation of boiling water reactor (BWR) responses to feedwater transients and small-break loss-of-coolant accidents (LOCAs) documented in NUREG-0626 which concludes that the number of S/RV challenges should be reduced. For the anticipated operational transients, a lower MSIV water level trip setpoint reduces the number of S/RV challenges. This is true not only because of the extra heat removal by the main condenser but also because of the operation of high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems that may significantly lower the reactor pressure during operational transients prior to isolation.

This modification lowers the isolation level of the following groups of valves from reactor vessel water level 2 to level 1:

Functional Type	MPL No.
Main Steam Isolation Valves	B21-F022A, B, C, D B21-F028A, B, C, D
Main Steam Drain Isolation Valves	B21-F016 B21-F019
Reactor Water Sample Line Isolation Valves	B31-F019 B31-F020

The proposed Technical Specifications revisions reflect this change. However, as justified in Appendices 1 and 2 of Reference 1, this modification constitutes neither an unreviewed safety question, nor a significant hazards consideration. No surveillance frequencies are affected by this modification; and with the exception of the setpoint modification itself, the LCO remains unchanged. Appendix 1 (page A1-4) of this document provides the results of the significant hazards review.

4B.3 Reactor Vessel Water Level - Low Low (Level 2) Trip Setpoint Modification (B21-N682A,B,C,D, B21-N692A,B,C,D)

The proposed Technical Specifications trip setpoint/allowable value for the reactor vessel water level 2 signal is ≥ -55 in. Reactor vessel water level 2 is for the initiation of HPCI and RCIC (B21-N692A,B,C,D). With the approval of section 4B.6 level 2 will also isolate reactor water cleanup and secondary containment and initiate the standby gas treatment system (B21-N682A,B,C,D).

Using Appendix K models, the Final Safety Analysis Report (FSAR) emergency core cooling system (ECCS) analysis was performed using a nominal analytical limit of -38 in. for level 2 HPCI actuation. However, the level 2 analytical limit is not a significant parameter in the Appendix K calculations. Therefore, as explained below, the ECCS calculations are insensitive to the variation in HPCI actuation water level so that a lower level 2 has no significant effect on the ECCS performance.

Sensitivity studies of the effect the level 2 analytical limit has on the ECCS analysis show that level 2 can be lowered all the way to the level 1 analytical limit (-152.5 in.) without affecting the results of that analysis. However, it has not been recommended that the level 2 analytical limit be lowered to -152.5 in. The proposed analytical limit of -58 in. was selected to provide the best flexibility and protective margin for the plant.

For small breaks, the limiting single failure is the HPCI failure. Even if HPCI is assumed operable, delaying the HPCI actuation has an insignificant effect on core heatup.

For the proposed change in the level 2 analytical limit to -58 in., the MAPLHGR[a] limit will not be changed. The requirements of 10 CFR 100 will still be met because:

- Reactor power level or inventory is not changed.
- Engineering standards are not changed.
- The probability of radioactive release will not be increased.

The trip setpoint/allowable value of ≥ -55 in. was developed from the newly established analytical limit using the criteria of Regulatory Guide 1.105. The designated trip setpoint for the plant will take into consideration instrument drift.

Therefore, this modification constitutes neither an unreviewed safety question, nor a significant hazards consideration. No surveillance frequencies are changed by this modification; and with the exception of the setpoint modification itself, the LCO remains unchanged. Appendix 1 (page A1-5) provides the results of the significant hazards review.

a. Maximum average planar linear heat-generation rate.

4B.4 Reactor Vessel Water Level - High (Level 8) Trip Instrumentation Modifications (B21-N693A,B,C,D)

After HPCI and RCIC have activated, this trip function prevents the water level in the reactor vessel from reaching the height of the main steam outlet. Its intended protective function is accomplished by tripping the HPCI steam turbine and the RCIC steam supply valves when the water level in the reactor vessel reaches the level 8 setting. The trip function is to protect the HPCI and RCIC steam turbine systems from potential damage.

This trip function is currently assigned to instruments B21-N017A,B,C,D which control the reactor protection system (RPS) reactor vessel water level 3 instrumentation. To separate the RPS and the ECCS functions, the ATTS design assigned the reactor vessel water level 8 trip function to the ECCS instrumentation. Since the functions of the level 8 trip remain the same, this modification constitutes neither an unreviewed safety question, nor a significant hazards consideration. Appendix 1 (page A1-6) provides the results of the significant hazards review.

The analytical limit for this function is 59.5 in. The trip setpoint/allowable value of ≤ 56.5 in. was developed using the criteria of Regulatory Guide 1.105. The designated trip setpoint for the plant will take into consideration setpoint drift.

4B.5 RCIC/Reactor Vessel Water Level 8 Trip Clarification

The present HNP-1 Technical Specifications state that when the reactor vessel water level - high (level 8) setpoint is reached, the RCIC turbine is tripped. Design Change Request 81-158 modified the RCIC system so that a level 8 trip does not electrically trip the turbine, but closes the steam supply valves. This allows the system to automatically reset when the water level drops below level 8, eliminating the need for manual reset of the system before the operator can take manual control over the system and avoid a fluctuating water level. The as-built notice for this change was issued on July 6, 1981.

This design change did not require a revision to the Technical Specifications. However, to avoid misinterpretation it is proposed that the Technical Specifications be revised. The proposed modification consists of adding a note to table 3.2-3 and the Bases, for the level 8 trip, stating that the system is capable of automatic reset after a level 8 trip. Since there is no change to the RCIC system or to the level 8 trip function, this modification constitutes neither an unreviewed safety question, nor a significant hazards consideration. Appendix 1 (page A1-7) provides the results of the significant hazards review.

4B.6 Lower Water Level Trip Setpoint for Isolation of Reactor Water Cleanup (RWCU) and Secondary Containment, and Starting of Standby Gas Treatment System (SGTS) (B21-N682A,B,C,D)

Reactor scram from normal power levels (above 50 percent of rated) usually results in a reactor vessel water level transient due to void collapse that causes isolation of the RWCU system at reactor water level 3. The result is typically the dropping of the cleanup filter cake, added radwaste processing, loss of ability to remove water from the reactor vessel immediately after scram, and other undesirable operational problems. These results adversely affect plant availability and operability. By lowering the isolation setpoint to reactor water level 2, these problems can be resolved without any adverse safety impact. The lowering of the level trip for isolation of RWCU from reactor water level 3 to reactor water level 2 will not have any adverse effect on plant transient and accident analysis. For any reactor pressure coolant boundary line breaks inside the primary containment, the LOCA design basis accident (DBA) analysis has shown that ECCS is capable of mitigating all break sizes up to and including the recirculation line break. For a RWCU line break outside the primary containment, the break detection is provided by the high differential flow, area high temperature, or area high ventilation differential temperature rather than by water level variation.

By lowering the SGTS actuation and secondary containment isolation from reactor water level 3 to reactor water level 2, the potential for spurious trips is reduced. The ECCS analysis design basis assumes that SGTS will initiate at the same time as the ECCS which initiates at reactor water level 2. The secondary containment, in conjunction with the SGTS, is designed to minimize any ground level release of radioactive material which may result from an accident; therefore, secondary containment should isolate at the same level at which the SGTS is actuated.

This modification has been implemented on other BWR/4s. The requirements of 10 CFR 100 are stil net. These changes to the plant constitute neither an unreviewed sa y question, nor a significant hazards consideration. Appendix 1 (page A1-8) provides the results of the significant hazards review.

4B.7 Deletion of High Drywell Pressure Signal for Residual Heat Removal (RHR) (Shutdown Cooling Mode) and RPV Head Spray Valve

High drywell pressure has been used as a signal to isolate the shutdown cooling mode of RHR. Small steam leaks in the drywell may cause a high drywell pressure signal which prohibits an acceptable normal shutdown procedure by preventing operation of the RHR system during the shutdown cooling mode. To resolve this operational and safety concern, the high drywell pressure signal would be deleted from the isolation logic for the RHR shutdown cooling suction valves and the reactor pressure vessel (RPV) head spray isolation valves.

The use of high drywell pressure as an isolation signal has little effect in preventing coolant losses due to an RHR pipe break inside the drywell since the inboard isolation valves are located as close as possible to the drywell wall. Such pipe breaks do not present a site boundary dose problem since the leaked fluid and associated radioactivity are completely retained within the primary containment boundary. The high drywell pressure signal for the RPV head spray valves will also be deleted. Since the RPV head spray valves are used as part of the shutdown cooling procedures, this change is consistent with the above proposed RHR (shutdown cooling mode) system modification.

This change does not affect the Appendix K calculation results presented in the FSAR. The requirements of 10 CFR 100 will still be met. This modification, therefore, constitutes neither an unreviewed safety question, nor a significant hazards consideration. Appendix 1 (page A1-9) provides the results of the significant hazards review.

A new valve group (6) must be assigned to Technical Specifications table 3.7-1 since the RHR reactor shutdown cooling suction supply valves (E11-F008, E11-F009) and the RHR reactor head spray isolation valves (E11-F022 and E11-F023) are now unique and isolate on reactor vessel water level - low (level 3) and reactor vessel steam dome pressure - low permissive. The reactor vessel steam dome pressure -low permissive trip was not included in the original Technical Specifications table 3.7-1, but was added to correct and clarify the Technical Specifications.

This modification has been implemented on other BWR/4s.

4B.8 Safety/Relief Valve Position Indicator Modifications

It was shown during qualification testing that the variable setting of the S/RV pressure switches could not hold their setpoints. To eliminate this problem, new switches were designed which do not have a variable setpoint capability. These switches are set at the factory at 85 psig. One of the two pressure switches on each S/RV has an indicating light associated with it. This light serves as primary indication of the position of the S/RV. Since table 3.2-11, Instrumentation Which Provides Surveillance Information, provides the type and range description of the S/RV primary indicator, it needs to be revised to reflect an indicating light at 85 psig. Also listed in table 3.2-11 is the S/RV secondary indicator. The type and range are currently given as a temperature element with a 0-600°F range. The instrument that provides surveillance is actually a recorder with a range of 0-600°F which receives input from the temperature element. Therefore, this table also needs to be revised to show a recorder rather than the temperature element. Since these changes only clarify the Technical Specifications and do not revise any setpoints, this modificiation does not introduce an unreviewed safety question or a significant hazards consideration. Appendix 1 (page A1-10) provides the results of the significant hazards review.

4B.9 Residual Heat Removal Shutdown Cooling Mode Safety Limit Modification

The present HNP-1 Technical Specifications list a safety limit of 135 psig for the reactor vessel steam dome pressure whenever operating the RHR system in the shutdown cooling mode. This value is incorrect. When the Technical Specifications were first written, the trip setpoint was accidentally listed in the safety limit section. As a result, a calculation was performed to determine the actual safety limit. From this calculation it was determined that a safety limit of 162 psig will prevent overpressurization of the RHR heat exchanger due to reactor pressure and RHR pump head. In addition, it was noticed that the bases statements for the safety limit and the limiting safety system are reversed.

This modification proposes to correct this error by changing the Technical Specifications safety limit from 135 psig to 162 psig. In addition, the bases for the safety limit and the limiting safety system settings will be corrected. Since these changes serve only to correct Technical Specifications errors, this modification constitutes neither an unreviewed safety question, nor a significant hazards consideration. Appendix 1 (page A1-11) provides the results of the significant hazards review.

4B.10 Elimination of MSIV Closure Scram in Startup Mode

The current Technical Specifications require a reactor scram on MSIV closure with the reactor in the startup/hot standby mode above 1045 psig vessel pressure. Since 1045 psig is the maximum allowable setpoint for the reactor trip on high pressure, the reactor will scram at 1045 psig in the startup/hot standby mode irregardless of MSIV position. This modification proposes to disable the scram function on MSIV closure in the startup/hot standby mode and delete the requirement from the Technical Specifications. This modification constitutes neither an unreviewed safety question, nor a significant hazards consideration. Appendix 1 (page A1-12) provides the results of the significant hazards review.

4B.11 Trip Function Identification Modifications

Several of the trip function descriptions were revised to correspond with the HNP-2 Technical Specifications and in some cases to the Standard Technical Specifications. Since these modifications are editorial in nature, an unreviewed safety question is not introduced, nor is a significant hazards consideration. Appendix 1 (page A1-13) provides the results of the significant hazards review.

4.B.12 Miscellaneous Trip Setpoint/Allowablc Value Modifications

4.B.12.a. New calculations were performed to determine the new setpoint value for each ATTS instrument. The setpoint calculations were made using the criteria of Regulatory Guide 1.105. The Plant Hatch analytical limits were used (where applicable) to develop the allowable values and trip setpoints. Unless identified in the text, the analytical limits used to develop these setpoints are the values used in the design basis of Plant Hatch. The values that are proposed to be inserted into the Technical Specifications are the calculated allowable values. The setpoints used at Plant Hatch will take into consideration instrument drift and will be developed from the allowable values. The proposed Technical Specifications revisions include modifications of the trip setpoints/allowable values for the following instruments:

RPS Trip Function	Trip Unit MPL No.
1. Reactor vessel steam dome pressure - high	B21-N678A,B,C,D
2. Reactor vessel water level - Level 3	B21-N680A,B,C,D
3. Reactor vessel water level - Level 1	B21-N681A,B,C,D

ECCS Trip Function	Trip Unit MPL No.
1. Reactor vessel water level - Level 1	B21-N691A,B,C,D
3. Reactor vessel steam dome pressure - low	B21-N690A,B,C,D
4. Reactor vessel steam dome presssure - low	B21-N690E,F B21-N641B,C
5. Reactor vessel water level - Level 3	B21-N695A,B

4B.12.b The bases for these proposed changes are as follows:

4B.12.b.1 <u>Setpoint Bases for Trip Functions Assigned to Reactor Protection System (RPS) Cabinets</u>

1. Reactor vessel steam dome pressure - high (B21-N678A,B,C,D)

   The analytical limit of 1071 psig is the value used in the plant transient analysis. The intent of this reactor scram function is to provide the nuclear system process barrier overpressure protection, because a rupture to the process barrier may result in the release of fission products. A pressure increase while operating also tends to increase the power of the reactor by collapsing voids, thus adding reactivity. A reactor scram quickly reduces the neutron flux, counteracting the pressure increase. The trip setpoint/allowable value of ≤1054 psig was developed using the criteria of Regulatory Guide 1.105. The designated trip setpoint for the plant will take into consideration instrument drift.

2. Reactor vessel water level - Level 3 (B21-N680A,B,C,D)

   Reactor vessel water level 3 is for isolation of primary contaiment, initiation of reactor scram, and for closure of RHR shutdown cooling isolation valves. The analytical limit of 7.5 in. was used to determine the trip setpoint and allowable value. A trip setpoint/allowable value of ≥ 8.5 in. was developed using the criteria of Regulatory Guide 1.105. The designated trip setpoint for the plant will take into consideration instrument drift.

3. Reactor vessel water level - Level 1 (B21-N681A,B,C,D)

   The analytical limit for this application is -152.5 in. The trip setpoint/allowable value of ≥ -121.5 in. was developed using the criteria of Regulatory Guide 1.105. The designated trip setpoint for the plant will take into consideration instrument drift.

4B.12.b.2 <u>Setpoint Basis for Trip Functions Assigned to ECCS Cabinets</u>

1. Reactor vessel water level - Level 1 (B31-N691A,B,C,D)

   The analytical limit of -152.5 in. is the value in the FSAR ECCS analysis for ADS, low-pressure coolant injection (LPCI), and containment spray initiation. The trip setpoint/allowable value of ≥ -121.5 in. was developed using the criteria of Regulatory Guide 1.105. The designated trip setpoint for the plant will take into consideration instrument drift.

2. Reactor vessel steam dome pressure - low (B21-N690A,B,C,D,E,F)

   These instrument channels monitor the reactor vessel pressure to provide the permissive signal for core spray and the injection permissive signal for RHR (LPCI). The analytical limit for this pressure permissive function has a range from 400 to 500 psig. The criterion for this setpoint is that it should be low enough to ensure that no overpressurization of the low-pressure ECCS occurs and high enough not to unnecessarily delay the flow injection of the low-pressure system. The trip setpoint/allowable value of ≥ 422 psig was developed using the lower analytical limit and the criteria of Regulatory Guide 1.105. The lower analytical limit was used because the important parameter is to ensure that RHR and core spray are operating as the pressure drops; therefore, a sign change of ≥ is required. Although the lower analytical limit was used to determine the new Technical Specifications value, the original Technical Specifications value of ≤ 500 psig is maintained. The designated trip setpoint for the plant will take into consideration instrument drift.

3. Reactor vessel steam dome pressure - low (B21-N690E,F; B21-N641B,C)

   An analytical limit of 300 psig is used in the Appendix K ECCS calculations. The intent of this trip function is to provide a permissive for closure of the recirculation discharge valves. The present Hatch setpoints of 310 psig, 318 psig, and 324 psig are above the analytical limit of 300 psig. Plant Hatch, therefore, has operated within its design basis. However, the current Technical Specifications value of ≤335 psig was set to ensure that the recirculation discharge valves would operate during accident conditions. An analytical limit of ≥300 psig and a nominal trip setpoint of 360 psig (determined using the criteria of Regulatory Guide 1.105) will meet the intent of the Technical Specifications value; therefore, a sign change is proposed. The trip setpoint/allowable value of ≥ 325 psig was developed using the criteria of Regulatory Guide 1.105.

4. Reactor vessel water level - Level 3 (B21-N695A,B)

   Reactor vessel level 3 provides an ADS permissive. The analytical limit of 7.5 in. was used in the FSAR ECCS analysis. The trip setpoint/allowable value of ≥ 8.5 in. was developed from the analytical limit using the criteria of Regulatory Guide 1.105. The designated trip setpoint for the plant will take into consideration instrument drift.

4B.12.c Conclusion

For the trip functions identified in this section, the analytical limits presented are such that neither transient nor safety analysis results documented in the FSAR are adversely affected. The uncertainities associated with instrument accuracy, calibration, and drift are considered in the setpoint determination. Therefore, it is concluded that the proposed instrumentation setpoint changes do not reduce the margin of safety of the current Technical Specifications, or change the FSAR setpoint bases and, therefore, constitute neither an unreviewed safety question as defined in 10 CFR 50.59, nor a significant hazards consideration as described in 10 CFR 50.92. Appendix 1 (page A1-14) provides the results of the significant hazards review.

V. SUMMARY

It can be concluded from the discussions of the preceding sections that the modifications do not introduce an unreviewed safety question, nor a significant hazards consideration. The upgrade program is designed to:

- Improve plant safety
- Reduce instrument drift LERs
- Increase plant reliability and availability
- Aid in meeting the requirements of IE Bulletin 79-01B, NUREG-0737, NUREG-0696, and NUREG-0661.

This submittal provides an overview of the evaluation and the justification for the proposed ATTS and the associated plant modifications to be incorporated into the Plant Hatch design during the 1984 refueling outage. The proposed Technical Specifications revisions are included in Section VI of this document. GPC will submit the proposed Technical Specification revisions for the remainder of the Hatch 1 ATTS modifications prior to the beginning of the 1985 refueling outage for that unit.

VI. PROPOSED TECHNICAL SPECIFICATIONS REVISIONS

The Technical Specifications for HNP-1 (Appendix A to Operating License DPR-57) are proposed for revision as presented in this section. The revisions are for the ATTS equipment which is scheduled for installation during the 1984 refueling outage. Table 6.1 provides the instructions for incorporating the revision(s).

TABLE 6.1

INSTRUCTIONS FOR INCORPORATING TECHNICAL SPECIFICATIONS REVISIONS

If the Technical Specifications revisions are accepted as proposed, the HNP-1 Technical Specifications (Appendix A to Operating License DPR-57) should be incorporated as follows:

Item	Deletions (Page)	Insertions (Page)	Applicable SER*[a] Section(s)
1	1.0-6	1.0-6	4.B.10
2	1.1-3	1.1-3	4.B.11, 4.B.12
3	1.1-4	1.1-4	4.B.10
4	1.1-5	1.1-5	4.B.3, 4.B.11, 4.B.12
5	1.1-13	1.1-13	4.B.11, 4.B.12
6	1.1-14	1.1-14	4.B.10
7	Fig. 2.1-1	Fig. 2.1-1	4.B.2, 4.B.3, 4.B.4, 4.B.11, 4.B.12
8	1.2-1	1.2-1	4.B.12
9	1.2-2	1.2-2	4.B.9
10	1.2-4	1.2-4	4.B.9
11	1.2-6	1.2-6, 6a	4.B.9
12	3.1-3	3.1-3	4.B.11, 4.B.12
13	3.1-4	3.1-4	4.B.11, 4.B.12
14	3.1-5	3.1-5	4.B.10
15	3.1-7	3.1-7	ATTS, 4.B.11
16	3.1-8	3.1-8	ATTS
17	3.1-11	3.1-11	4.B.11
18	3.1-12	3.1-12	4.B.11, 4.B.12
19	3.1-14	3.1-14	ATTS
20	3.1-15	3.1-15	ATTS
21	3.1-17	3.1-17	ATTS
22	3.1-18	3.1-18	ATTS
23	3.2-1	3.2-1	4.B.1
24	3.2-2	3.2-2	4.B.2, 4.B.3, 4.B.6, 4.B.11, 4.B.12
25	3.2-5	3.2-5	4.B.3, 4.B.4, 4.B.11, 4.B.12
26	3.2-8	3.2-8	4.B.3, 4.B.4, 4,B.5, 4.B.11, 4.B.12
27	3.2-10	3.2-10	4.B.11, 4.B.12
28	3.2-11	3.2-11	4.B.11, 4.B.12
29	3.2-14	3.2-14	4.B.11, 4.B.12
30	3.2-20	3.2-20	4.B.3
31	3.2-22	3.2-22	4.B.8
32		3.2-23c	4.B.1
33	3.2-24	3.2-24	ATTS, 4.B.11
34	3.2-27	3.2-27	ATTS, 4.B.11
35	3.2-30	3.2-30	ATTS, 4.B.11
36	3.2-33	3.2-33	ATTS, 4.B.11
37	3.2-35	3.2-35	ATTS, 4.B.11
38	3.2-38	3.2-38	ATTS, 4.B.11

Item	Deletions (Page)	Insertions (Page)	Applicable SER*[a] Section(s)
39	3.2-45	3.2-45	4.B.11
40		3.2-49c	4.B.1
41	3.2-50	3.2-50, 50a	4.B.2, 4.B.3, 4.B.6, 4.B.9, 4.B.11, 4.B.12
42	3.2-52	3.2-52	Editorial, 4.B.3, 4.B.11, 4.B.12
43	3.2-53	3.2-53	ATTS, 4.B.4, 4.B.11, 4.B.12
44	3.2-55	3.2-55	Editorial, ATTS, 4.B.3, 4.B.11
45	3.2-56	3.2-56	ATTS, 4.B.4, 4.B.5, 4.B.11,
46	3.2-58	3.2-58	4.B.11, 4.B.12
47	3.2-59	3.2-59	4.B.12
48	3.2-60	3.2-60	4.B.12
49	3.2-62	3.2-62	4.B.11, 4.B.12
50	3.2-68a	3.2-68a	4.B.1
51	3.2-69	3.2-69	ATTS
52	3.6-9	3.6-9	4.B.1
53	3.6-9a	3.6-9a, 9b	4.B.1
54	3.6-21	3.6-21	4.B.1
55	3.6-22	3.6-22	4.B.1
56	3.7-17	3.7-17	4.B.7
57	3.7-18	3.7-18	4.B.7
58	3.7-19	3.7-19	4.B.7, 4.B.11, 4.B.6, 4.B.2
59	3.7-35	3.7-35	4.B.2, 4.B.6, 4.B.7, 4.B.11

* SER-Safety Evaluation Report

a. 1. ATTS refers to proposed revisions justified in Section III of this submittal.
   2. 4B.1 through 4B.12 refer to justifications presented in Section IV of this submittal.
   3. Editorial refers to the correction of a typographical error.

GG. Simulated Automatic Actuation - Simulated automatic actuation means applying a simulated signal to the sensor to actuate the circuit in question.

HH. Start & Hot Standby Mode - The reactor is in the Start & Hot Standby Mode when the Mode Switch is in the START & HOT STANDBY position. In this mode the reactor protection system is energized with IRM and APRM (Start & Hot Standby Mode) neutron monitoring system trips and control rod withdrawal inter-locks in service.

II. Surveillance Frequency - Periodic surveillance tests, checks, calibrations, and examinations shall be performed within the specified surveillance intervals. These intervals may be adjusted plus or minus 25%. The operating cycle interval as pertaining to instrument and electrical surveillance shall never exceed 15 months. In the case where the elapsed interval has exceeded 100% of the specified interval, the next surveillance interval shall commence at the end of the original specified interval.

JJ. Surveillance Requirements - The surveillance requirements are requirements established to ensure that the Limiting Conditions for Operation as stated in Section 3 of these Technical Specifications are met. Surveillance requirements are not required on systems or parts of systems that are not required to be operable or are tripped. If tests are missed on parts not required to be operable or are tripped, then they shall be performed prior to returning the system to an operable status.

KK. Total Peaking Factor (TPF) - The total peaking factor is the highest product of radial, axial, and local peaking factors simultaneously operative at any segment of fuel rod.

LL. Transition Boiling - Transition boiling is the boiling that occurs between nucleate and film boiling. Transition boiling is manifested by an unstable fuel cladding surface temperature, rising suddenly as steam blanketing of the heat transfer surface occurs, then dropping as the steam blanket is swept away by the coolant flow, then rising again.

2.1.A.1.d. APRM Rod Block Trip Setting

The APRM rod block trip setting shall be:

$$S_{RB} \leq 0.66\ W + 42\%$$

where:

S_{RB} = Rod block setting in percent of rated thermal power (2436 MWt)

W = Loop recirculation flow rate in percent of rated (rated loop recirculation flow rate equals 34.2×10^6 lb/hr)

In the event of operation with a core maximum fraction of limiting power density (CMFLPD) greater than the fraction of rated core thermal power $\left(\frac{\text{Core MW Thermal}}{2436}\right)$, the ARPM gain shall be adjusted up to 95% of rated thermal power as follows:

APRM Reading ≥ 100% x CMFLPD

Provided that the adjusted APRM reading does not exceed 100% of rated thermal power and the required gain adjustment increment does not exceed 10% of rated thermal power.

2. Reactor Vessel Water Low Level Scram Trip Setting (Level 3)

Reactor vessel water low level scram trip setting (Level 3) shall be ≥ 8.5 inches (narrow range scale).

3. Turbine Stop Valve Closure Scram

Turbine stop valve closure scram trip setting shall be ≤ 10 percent valve closure from full open. This scram is only effective when turbine steam flow is above 30% of rated, as measured by turbine first stage pressure.

2.1.A.4. Turbine Control Valve Fast Closure Scram Trip Setting

Turbine control valve fast closure scram trip shall initiate within 30 milliseconds of start of control valve fast closure. Fast closure is sensed by measuring electro-hydraulic control oil line pressure which decreases rapidly upon generator load rejection and just prior to fast closure of the control valves. This scram is only effective when turbine steam flow is above 30% of rated, as measured by turbine first stage pressure.

5. Main Steam Line Isolation Valve Closure Scram Trip Setting

Scram trip setting from main steam line isolation valve closure shall be ≤ 10 percent valve closure from full open. This scram is effective in the Run Mode.

6. Main Steam Line Isolation Valve Closure on Low Pressure

Main steam line isolation valve closure on low pressure at inlet to turbine valves shall occur at ≥ 825 psig, while in the Run Mode.

7. Main Steam Line Isolation Valve Closure on Low Condenser Vacuum

Main steam line isolation valve closure on low condenser vacuum shall occur at ≥ 7 inches Hg vacuum.

2.1.B. Reactor Vessel Water Level Trip Settings Which Initiate Core Standby Cooling Systems (CSCS)

Reactor vessel water level trip settings which initiate core standby cooling systems shall be as shown in Tables 3.2-2 thru 3.2-6 at normal operating conditions.

1. HPCI Actuation (Level 2)

   HPCI actuation (Level 2) shall occur at a water level ≥ -55 inches.

2. Core Spray and LPCI Actuation (Level 1)

   Core Spray and LPCI actuation (Level 1) shall occur at a water level ≥ -121.5 inches.

2.1.A.1.c APRM Flux Scram Trip Settings (Run Mode) (Continued)

The APRM flow referenced scram trip setting at full recirculation flow is adjustable up to 120% of rated power. This reduced flow referenced trip setpoint will result in an earlier scram during slow thermal transients, such as the loss of 80°F feedwater heating event, than would result with the 120% fixed high neutron flux scram trip. The lower flow referenced scram setpoint therefore decreases the severity (ΔCPR) of a slow thermal transient and allows lower Operating Limits if such a transient is the limiting abnormal operational transient during a certain exposure interval in the cycle.

The APRM fixed high neutron flux signal does not incorporate the time constant, but responds directly to instantaneous neutron flux. This scram setpoint scrams the reactor during fast power increase transients if credit is not taken for a direct (position) scram, and also serves to scram the reactor if credit is not taken for the flow referenced scram.

The APRM reading must be adjusted to ensure that the LHGR transient peak is not increased for any combination of CMFLPD and reactor core thermal power. The APRM reading is adjusted in accordance with the formula in Specification 2.1.A.1.c., when the CMFLPD is greater than the fraction of rated core thermal power.

Analyses of the limiting transients show that no scram adjustment is required to assure MCPR > 1.07 when the transient is initiated from the operating MCPR limit.

d. APRM Rod Block Trip Setting

Reactor power level may be varied by moving control rods or by varying the recirculation flow rate. The APRM system provides a control rod block to prevent rod withdrawal beyond a given point at constant recirculation flow rate, and thus to protect against the condition of a MCPR less than 1.07. This rod block trip setting, which is automatically varied with recirculation loop flow rate, prevents an increase in the reactor power level to excessive values due to control rod withdrawal. The flow variable trip setting provides substantial margin from fuel damage, assuming a steady-state operation at the trip setting, over the entire recirculation flow range. The margin to the Safety Limit increases as the flow decreases for the specified trip setting versus flow relationship; therefore, the worst case MCPR which would occur during a steady-state operation is at 108% of rated thermal power because of the APRM rod block trip setting. The actual power distribution in the core is established by specified control rod sequences and is monitored continuously by the in-core LPRM system. The APRM reading is adjusted to compensate for a CMFLPD greater than the fraction of rated core thermal power.

2. Reactor Vessel Water Low Level Scram Trip Setting (Level 3)

The trip setting for low level scram is above the bottom of the separator skirt. This level is > 14 feet above the top of the active fuel. This level has been used in transient analyses dealing with coolant inventory decrease. The results reported in FSAR Section 14.3 show that a scram at this level adequately protects the fuel and the pressure barrier. The designated scram trip setting is at least 22 inches below the bottom of the normal operating range and is thus adequate to avoid spurious scrams.

2.1.A.3. Turbine Stop Valve Closure Scram Trip Settings

The turbine stop valve closure scram trip anticipates the pressure, neutron flux and heat flux increase that could result from rapid closure of the turbine stop valves. With a scram trip setting of ≤ 10 percent of valve closure from full open, the resultant increase in surface heat flux is limited such that MCPR remains above 1.07 during the worst case transient that assumes the turbine bypass is closed. This scram is bypassed when turbine steam flow is below 30% of rated, as measured by turbine first stage pressure.

4. Turbine Control Valve Fast Closure Scram Trip Setting

This turbine control valve fast closure scram anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection exceeding the capability of the turbine bypass. The Reactor Protection System initiates a scram when fast closure of the control valves is initiated by the fast acting solenoid valves. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic control oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the reactor protection system. This trip setting, a nominally 50% greater closure time and a different valve characteristic from that of the turbine stop valve, combine to produce transients very similar and no more severe than for the stop valve. This scram is bypassed when turbine steam flow is below 30% of rated, as measured by turbine first stage pressure.

5. Main Steam Line Isolation Valve Closure Scram Trip Setting

The main steam line isolation valve closure scram occurs within 10% of valve movement from the fully open position and thus anticipates the neutron flux and pressure scrams which remain as available backup protection. This scram function is bypassed automatically when the Mode Switch is not in the RUN position.

6. Main Steam Line Isolation Valve Closure on Low Pressure

The low pressure isolation of the main steam lines at 825 psig was provided to protect against rapid reactor depressurization and the resulting rapid cooldown of the vessel, which might result from a pressure regulator failure causing inadvertent opening of the control and/or bypass valves.

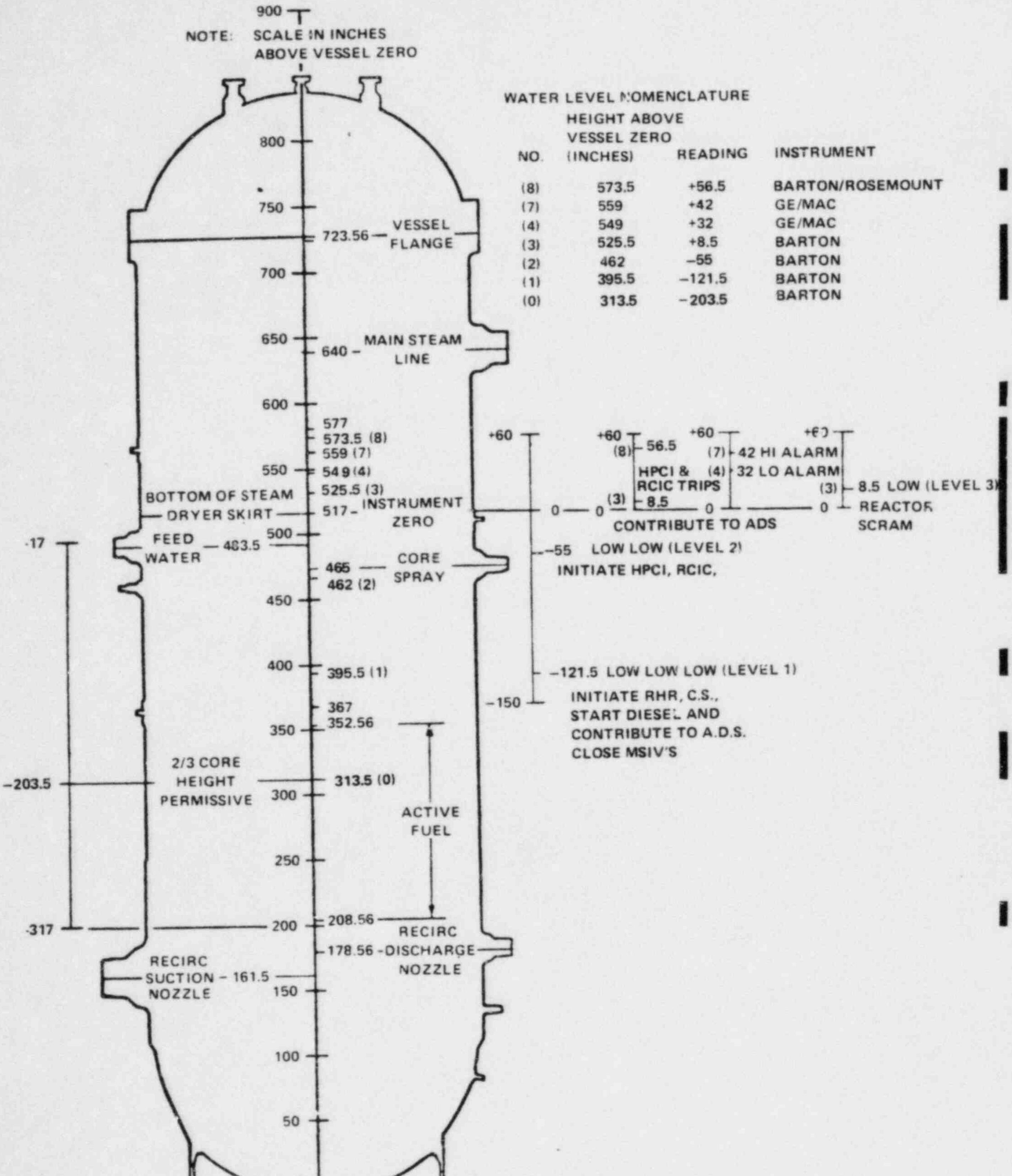


FIGURE 2.1-1
REACTOR VESSEL WATER LEVEL

2.2 REACTOR COOLANT SYSTEM INTEGRITY (Safety Limits)

Applicability

The Safety Limit, established to preserve the reactor coolant system integrity, applies to the limit on the reactor vessel steam dome pressure.

Objective

The objective of the Safety Limit (associated with preserving the reactor coolant system integrity) is to establish a pressure limit below which the integrity of the reactor coolant system is not threatened due to any overpressure condition.

Specifications

A. Reactor Vessel Steam Dome Pressure

1. When Irradiated Fuel is in the Reactor

The reactor vessel steam dome pressure shall not exceed 1325 psig at any time when irradiated fuel is present in the reactor vessel.

2.2 REACTOR COOLANT SYSTEM INTEGRITY (Limiting Safety System Settings)

Applicability

The Limiting Safety System Settings apply to trip settings of the instruments and devices which are provided to prevent the reactor vessel steam dome pressure Safety Limit from being exceeded.

Objective

The objective of the Limiting Safety System Settings is to define the level of the process variables at which automatic protective action is initiated to prevent the reactor vessel steam dome pressure Safety Limit from being exceeded.

Specifications

A. Nuclear System Pressure

1. When Irradiated Fuel is in the Reactor

When irradiated fuel is present in the reactor vessel, and the head is bolted to the vessel, the limiting safety system settings shall be as specified below:

Protective Action	Limiting Safety System Settings (psig)
a. Scram on high reactor pressure (reactor vessel steam dome pressure)	≤ 1054
b. Nuclear system relief valves open on nuclear system pressure	4 valves at 1080 4 valves at 1090 3 valves at 1100

2.2.A Nuclear System Pressure (cont.)

The allowable setpoint relief error for each valve shall be ± 1%. In the event that an installed safety-relief valve requires replacement, a spare valve whose setpoint is lower than that of the failed valve may be substituted for the failed valve until the first refueling outage following such substitution. No more than two valves with lower setpoints may be substituted in place of valves with higher setpoints. Spare valves which are used as substitutes under the abovementioned provisions shall have a setpoint equal to 1080 psig ±1% or 1090 psig ±1%.

1.2.A.2. When Operating The RHR System in the Shutdown Cooling Mode

The reactor vessel steam dome pressure shall not exceed 162 psig at any time when operating the RHR system in the Shutdown Cooling Mode.

2.1.A.2. When Operating The RHR System in the Shutdown Cooling Mode

The reactor pressure trip setting which closes (on increasing pressure) or permits opening (on decreasing pressure) of the shutdown cooling isolation valves shall be ≤ 135 psig.

1.2.A.2. <u>When Operating the RHR System in the Shutdown Cooling Mode</u>

The design pressure of the shutdown cooling piping of the Residual Heat Removal System is not exceeded with the reactor vessel steam dome pressure less than 162 psig.

2.2 REACTOR COOLANT SYSTEM INTEGRITY

A. Nuclear System Pressure

1. When Irradiated Fuel is in the Reactor

The 11 relief/safety valves are sized and set point pressures are established in accordance with the following requirements of Section III of the ASME Code:

a. The lowest relief/safety valve must be set to open at or below vessel design pressure and the highest relief/safety valve must be set to open at or below 105% of design pressure.

b. The valves must limit the reactor pressure to no more than 110% of design pressure.

The primary system relief/safety valves are sized to limit the primary system pressure, including transients, to the limits expressed in the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels. No credit is taken from a scram initiated directly from the isolation event, or for power operated relief/safety valves, sprays, or other power operated pressure relieving devices. Thus, the probability of failure of the turbine-generator trip SCRAM or main steam isolation valve closure SCRAM is conservatively assumed to be unity. Credit is taken for subsequent indirect protection system action such as neutron flux SCRAM and reactor high pressure SCRAM, as allowed by the ASME Code. Credit is also taken for the dual relief/safety valves in their ASME Code qualified mode of safety operation. Sizing on this basis is applied to the most severe pressurization transient, which is the main steam isolation valves closure, starting from operation at 105 percent of the reactor warranted steamflow condition.

Reference 2, Figure 4 shows peak, vessel bottom pressures attained when the main steam isolation valve closure transients are terminated by various modes of reactor scram, other than that which would be initiated directly from the isolation event (trip scram). Relief/safety valve capacities for this analysis are 84.0 percent, representative of the 11 relief/safety valves.

The relief/safety valve settings satisfy the Code requirements for relief/ safety valves that the lowest valve set point be at or below the vessel design pressure of 1250 psig. These settings are also sufficiently above the normal operating pressure range to prevent unnecessary cycling caused by minor transients. The results of postulated transients where inherent relief/safety valve actuation is required are given in Section 14.3 of the FSAR.

2. When Operating the RHR System in the Shutdown Cooling Mode

An interlock exists in the logic for the RHR shutdown cooling valves, which are normally closed during power operation, to prevent opening of the valves above a preset pressure setpoint of 135 psig. This setpoint is selected to assure that pressure integrity of the RHR system is maintained. Administrative operating procedures require the operator to close these shutdown cooling valves prior to pressure operation. However, as a backup, the interlock will automatically close these valves when the pressure setpoint is reached. Double indicating lights will be provided in the control room for valve position indication.

Table 3.1-1

REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION REQUIREMENTS

When the reactor is subcritical and the reactor water temperature is less than 212°F, only the following sources of scram trip signals need to be operable:

Mode Switch in SHUTDOWN
Manual Scram
IRM High High Flux
Scram Discharge Volume High High Level

Scram Number (a)	Source of Scram Trip Signal		Operable Channels Required Per Trip System (b)	Scram Trip Setting	Source of Scram Signal is Required to be Operable Except as Indicated Below
1	Mode Switch in SHUTDOWN		1	Mode Switch in SHUTDOWN	Automatically bypassed two seconds after the Mode Switch is placed in the SHUTDOWN position.
2	Manual Scram		1	Depression of Manual Scram Button	
3	IRM	High High Flux	3	$\leq$120/125 of full scale Tech Spec 2.1.A.1.a	IRMs are automatically bypassed when APRMs are on scale and the Mode Switch is in the Run position.
		Inoperative	3	Not Applicable	IRMs are automatically bypassed when APRMs are on scale and the Mode Switch is in the RUN position.
4	Reactor Vessel Steam Dome Pressure - High		2	$\leq$1054 psig Tech Spec 2.2.A.1	Not required when reactor head is not bolted to the vessel.

Table 3.1-1 (Cont'd)

Scram Number (a)	Source of Scram Trip Signal	Operable Channels Required Per Trip System (b)	Scram Trip Setting	Source of Scram Signal is Required to be Operable Except as Indicated Below
5	High Drywell Pressure	2	$\leq$ 2 psig	Not required to be operable when primary containment integrity is not required. May be bypassed when necessary during purging for containment inerting or deinerting.
6	Reactor Vessel Water Level - Low (Level 3)	2	$\geq$ 8.5 inches	
7	Scram Discharge Volume High High Level			Permissible to bypass (initiates control rod block) in order to reset RPS when the Mode Switch is in the REFUEL or SHUTDOWN position.
	a. Float Switches		$\leq$71 gallons	
	b. Thermal Level Sensors		$\leq$71 gallons	
8	APRM Flow Referenced Neutron Flux	2	$S \leq 0.66W+54\%$ (Not to exceed 117%) Tech Spec 2.1.A.1.c	
	Fixed High Neutron Flux	2	$S \leq 120\%$ Power Tech Spec 2.1.A.1.c	
	Inoperative	2	Not Applicable	An APRM is inoperable if there are less than two LPRM inputs per level or there are less than 11 LPRM inputs to the APRM channel.

Table 3.1-1 (Cont'd)

Scram Number (a)	Source of Scram Trip Signal		Operable Channels Required Per Trip System (b)	Scram Trip Setting	Source of Scram Signal is Required to be Operable Except as Indicated Below
8	APRM	Downscale	2	$\geq$ 3/125 of full scale	The APRM downscale trip is active only when the Mode Switch is in RUN. The APRM downscale trip is automatically bypassed when the IRM instrumentation is operable and not tripped.
		15% Flux	2	$\leq$ 15/125 of full scale Tech Spec 2.1.A.1.b	The APRM 15% Scram is automatically bypassed when the Mode Switch is in the RUN position.
9	Main Steam Line Radiation		2	$\leq$ 3 times normal background at rated thermal power.	Not required if all steam lines are isolated.
10	Main Steam Line Isolation Valve Closure		4	$\leq$ 10% valve closure from full open Tech Spec 2.1.A.5	Automatically bypassed when the Mode Switch is not in the RUN position. The design permits closure of any two lines without a scram being initiated..
11	Turbine Control Valve Fast Closure		2	Within 30 milliseconds of the start of control valve fast closure Tech Spec 2.1.A.4.	Automatically bypassed when turbine steam flow is below 30% of rated as measured by turbine first stage pressure.

Table 4.1-1

Reactor Protection System (RPS) Instrumentation Functional Test, Functional Test Minimum Frequency, and Calibration Minimum Frequency

Scram Number (a)	Source of Scram Trip Signal	Group (b)	Instrument Functional Test Minimum Frequency (c)	Instrument Calibration Minimum Frequency
1	Mode Switch in SHUTDOWN	A	Once/Operating Cycle	Not Applicable
2	Manual Scram	A	Every 3 months	Not Applicable
3	IRM High High Flux	C	Once/Week during refueling and within 24 hours of Startup (e)	Once/Week
	Inoperative	C	Once/week during refueling and within 24 hours of Startup (e)	Once/Week
4	Reactor Vessel Steam Dome Pressure - High	D	Once/Month	Once/operating cycle
5	High Drywell Pressure	A	Once/Month(f)	Every 3 months
6	Reactor Vessel Water Level - Low (Level 3)	D	Once/Month (g)	Once/Operating Cycle
7	Scram Discharge Volume High High Level			
	a. Float Switches	A	Once/Month (f)	(h)
	b. Thermal Level Sensors	B	Once/Month (f)	Once/operating cycle
8	APRM Fixed High Flux	B	Once/Week (e)	Twice/Week
	Inoperable	B	Once/Week (e)	Twice/Week
	Downscale	B	Once/Week (e)	Twice/Week
	Flow Reference	B	Once/Week (f)	Once/Operating Cycle
	15% Flux	C	Within 24 Hours of Startup (e)	Once/Week

Table 4.1-1 (Cont.)

9	Main Steam Line High Radiation	B	Once/Week (e)	Every 3 months (i)
10	Main Steam Line Isolation Valve Closure	A	Once/Month (f)	(h)
11	Turbine Control Valve Fast Closure	A	Once/Month (f) (j)	Once/Operating Cycle (k)
12	Turbine Stop Valve Closure	A	Once/Month (f)	(h)
	RPS Channel Switch	A	Once/Operating Cycle	Not Applicable
	Turbine First Stage Pressure Permissive	A	Every 3 months	Every 6 months
	Reactor Pressure Permissive	A	Every 3 months	Every 6 months
	LPRM Signal	B		Every 1000 Effective Full Power Hours

a. The column entitled "Scram Number" is for convenience so that a one-to-one relationship can be established between items in Table 4.1-1 and items in Table 3.1-1.

b. The definition for each of the four groups is as follows:

Group A. On-off sensors that provide a scram trip signal.
Group B. Analog devices coupled with bi-stable trips that provide a scram trip signal.
Group C. Devices which only serve a useful function during some restricted mode of operation, such as startup or shutdown, or for which the only practical test is one that can be performed at shutdown.
Group D. Analog transmitters and trip units that provide a scram trip function.

c. Functional tests are not required when the systems are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the systems to an operable status.

3.1.A.2. Manual Scram

The manual scram function is active in all modes, thus providing for a manual means of rapidly inserting control rods during all modes of reactor operation.

3. IRM

The bases for the IRM High High Flux Scram Trip Setting are discussed in the bases for Specification 2.1.A.1.a. Each protection trip system has one more IRM channel than is necessary to meet the minimum number required. This allows the bypassing of one IRM channel per protection trip system for maintenance, testing or calibration.

a. High High Flux
The IRM system provides protection against excessive power levels and short reactor periods in the source and intermediate power ranges. The requirement that the IRM's be inserted in the core until the APRM's read 3/125 of full scale or greater assures that there is proper overlap in the neutron monitoring systems and thus, that adequate coverage is provided for all ranges of reactor operation.

A source range monitor (SRM) system is also provided to supply additional neutron level information during start-up but has no scram function (Section 7.5.4 FSAR). Thus, the IRM and APRM systems are required in the Refuel and Start & Hot Standby modes. In the power range, the APRM system provides the required protection (Section 7.5.7 FSAR). Thus, the IRM System is not required when the APRM's are on scale and the Mode Switch is in the RUN position.

b. Inoperative
When an IRM channel becomes unable to perform its normal monitoring function, the condition is recognized and an inopertive trip results. This trip is given the same logic significance as the upscale trip; thus the faulty channel immediately fails safe by contributing to a potential scram condition.

4. Reactor Vessel Steam Dome Pressure - High

High pressure within the nuclear system poses a direct threat of rupture to the nuclear system process barrier. A nuclear system pressure increase while the reactor is operating compresses the steam voids and results in a positive reactivity insertion causing increased core heat generation that could lead to fuel failure and system over-pressurization. A scram counteracts a pressure increase by quickly reducing the core fission heat generation.

The nuclear system high pressure scram setting is chosen slightly above the reactor vessel maximum normal operation pressure to permit normal operation without spurious scrams yet provide a wide margin to the maximum allowable nuclear system pressure. The location of the pressure measurement, as compared to the location of highest nuclear system pressure during transients, was also considered in the selection of the high pressure scram setting. The nuclear system high pressure scram works in conjunction with the pressure relief system in preventing nuclear system pressure from exceeding the maximum allowable pressure. This same nuclear system high pressure scram

3.1.A.4. Reactor Vessel Steam Dome Pressure - High (Continued)

setting also protects the core from exceeding thermal hydraulic limits as a result of pressure increases from some events that occur when the reactor is operating at less than rated power and flow.

5. High Drywell Pressure

Pressure switch instrumentation for the drywell is provided to detect a loss of coolant accident and initiate the core standby cooling equipment. A high drywell pressure scram is provided at the same setting (≤2 psig) as the core standby cooling systems initiation to minimize the energy which must be accommodated during a loss of coolant accident. The instrumentation is a backup to the reactor vessel water level instrumentation.

6. Reactor Vessel Water Level - Low (Level 3)

The bases for the Reactor Vessel Water Level-Low Scram Trip Setting (Level 3) are discussed in the bases for Specification 2.1.A.2.

7. Scram Discharge Volume High High Level

The control rod drive scram system is designed so that all of the water which is discharged from the reactor by a scram can be accommodated in the discharge piping. A part of this piping is an instrument volume which is the low point in the piping. No credit was taken for this volume in the design of the discharge piping as concerns the amount of water which must be accommodated during a scram. During normal operation the discharge volume is empty; however, should the discharge volume fill with water, the water discharged to the piping from the reactor could not be accommodated which would result in a slow scram time or partial or no control rod insertion. To preclude this occurrence, level switches have been provided in the instrument volume which scram the reactor when the volume of water reaches 71 gallons. As indicated above, there is sufficient volume in the piping to accommodate the scram without impairment of the scram times or amount of insertion of the control rods. This function shuts the reactor down while sufficient volume remains to accommodate the discharged water and precludes the situation in which a scram would be required but not able to perform its function adequately.

8. APRM

Three APRM instrument channels are provided for each protection trip system. APRM's A and E operate contacts in one trip logic and APRM's C and E operate contacts in the other trip logic. APRM's B, D and F are arranged similarly in the other protection trip system. Each protection trip system has one more APRM than is necessary to meet the minimum number required per channel. This allows the bypassing of one APRM per protection trip system for maintenance, testing or calibration.

a. Flow Referenced and Fixed High Neutron Flux

The bases for the APRM Flow Referenced and Fixed High Neutron Flux Scram Trip Settings are discussed in the bases for Specification 2.1.A.1.c.

3.1.B. RPS Response Time

Component electrical characteristics are selected so that the system response time, from the opening of a sensor contact up to and including the opening of the trip actuator contacts, is less than 50 milliseconds. A 50 millisecond time delay plus control rod movement and sensor delay time is used in the various transient analyses. For the analog transmitter trip system (ATTS) instrumentation, the sensor consists of a transmitter and the associated trip unit.

C. References

1. FSAR Section 7.2, Reactor Protection System

2. FSAR Section 7.5.4, Source Range Monitor Subsystem

3. FSAR Section 7.5.7, Average Power Range Monitor Subsystem

4. IEEE Standard 279-1971 Criteria for Protection Systems for Nuclear Power Generating Stations

4.1 REACTOR PROTECTION SYSTEM (RPS)

A. Test and Calibration Requirements for the RPS

The minimum functional testing frequency used in this specification is based on a reliability analysis using the concepts developed in Reference 1 and the surveillance frequencies for ATTS equipment approved by the NRC in Reference 2. These concepts were specifically adapted to the one out of two taken twice logic of the reactor protection system. The analysis shows that the sensors are primarily responsible for the reliability of the reactor protection system. This analysis makes use of unsafe failure rate experience at conventional and nuclear power plants in a reliability model for the system. An unsafe failure is defined as one which negates channel operability and which, due to its nature, is revealed only when the channel is functionally tested or attempts to respond to a real signal. Failures such as blown fuses, ruptured bourdon tubes, faulted amplifiers, faulted cables, etc., which result in upscale or downscale readings on the reactor instrumentation are safe and will be easily recognized by the operators during operation because they are revealed by an alarm or a scram.

The channels listed in Table 4.1-1 are divided into four groups for functional testing. These are:

Group A. On-Off Sensors that provide a scram trip function.
Group B. Analog devices coupled with bi-stable trips that provide a scram function.
Group C. Devices which only serve a useful function during some restricted mode of operation, such as startup or shutdown, or for which the only practical test is one that can be performed at shutdown.
Group D. Analog transmitters and trip units that provide a scram trip function.

The sensors that make up Group A are specifically selected from among the whole family of industrial on-off sensors that have earned an excellent reputation for reliable operation. During design, a goal of 0.99999 probability of success at the 50% confidence level was adopted to assure that a balanced and adequate design is achieved. The probability of success is primarily a function of the sensor failure rate and the test interval. A three-month test interval was planned for Group A sensors. This is in keeping with good operating practices, and satisfies the design goal for the logic configuration utilized in the Reactor Protection System.

To satisfy the long-term objective of maintaining an adequate level of safety throughout the plant lifetime, a minimum goal of 0.9999 at the 95% confidence level is proposed. With the one out of two taken twice logic, this requires that each sensor have an availability of 0.993 at the 95% confidence level. This level of availability may be maintained by adjusting the test interval as a function of the observed failure history (Ref. 1). To facilitate the implementation of this technique, Figure 4.1-1 is provided to indicate an appropriate trend in test interval. The procedure is as follows:

1. Like sensors are pooled into one group for the purpose of data acquisition.

2. The factor M is the exposure hours and is equal to the number of sensors

4.1.A. Test and Calibration Requirements for the RPS (Continued)

Group C devices are active only during a given portion of the operational cycle. For example, the IRM is active during startup and inactive during full-power operation. Thus, the only test that is meaningful is the one performed just prior to shutdown or startup; i.e., the tests that are performed just prior to use of the instrument.

Calibration frequency of the instrument channel is divided into two categories: They are as follows:

i. Passive type indicating devices that can be compared with like units on a continuous reference.

ii. Vacuum tube or semiconductor devices and detectors that drift or lose sensitivity.

Experience with passive type instruments in generating stations and substations indicates that the specified calibrations are adequate. For those devices which employ amplifiers, etc., drift specifications call for drift to be less than 0.4%/month; i.e., in the period of a month a drift of .4% could occur and still provide for adequate margin. For the APRM system, drift of electronic apparatus is not the only consideration in determining a calibration frequency. Change in power distribution and loss of chamber sensitivity dictate a calibration every seven (7) days. Calibration on this frequency assures plant operation at or below thermal limits.

The sensitivity of LPRM detectors decreases with exposure to neutron flux at a slow and approximately constant rate. This is compensated for in the APRM system by calibrating twice a week using heat balance data and by calibrating individual LPRM's every 1000 effective full power hours using TIP traverse data.

Group D devices consist of analog transmitters, master trip units, slave trip units, and other accessories. The general description of the ATTS devices is provided in Reference 3. As evidenced by NEDO-21617-A, the NRC has approved the following surveillance frequencies for ATTS equipment:

1. Once per shift for channel check
2. Once per month for channel functional test
3. Once per operating cycle for channel calibration

B. Maximum Fraction of Limiting Power Density (MFLPD)

Since changes due to burnup are slow, and only a few control rods are moved daily, a daily check of the MFLPD is adequate. The determination of the MFLPD would establish whether or not adjustment of the APRM reading is required.

4.1.C. References

1. I. M. Jacobs, "Reliability of Engineered Safety Features as a Function of Testing Frequency," Nuclear Safety, Volume 9, No. 4, July-August, 1968, pp 303-312.

2. NEDO-21617-A, "Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Trip Inputs."

3. NEDE-22154-1, "Analog Trip System for Engineered Safeguard Sensor Trip Inputs - Edwin I. Hatch Nuclear Plant Units 1 and 2."

3.2 PROTECTIVE INSTRUMENTATION

Applicability

The Limiting Conditions for Operation apply to the plant instrumentation which performs a protective function.

Objective

The objective of the Limiting Conditions for Operation is to assure the operability of protective instrumentation.

Specifications

The Limiting Conditions for Operation of the protective instrumentation affecting each of the following protective actions shall be as indicated in the corresponding LCO table.

4.2 PROTECTIVE INSTRUMENTATION

Applicability

The Surveillance Requirements apply to the instrumentation which performs a protective function.

Objective

The objective of the Surveillance Requirements is to specify the type and frequency of surveillance to be applied to protective instrumentation.

Specifications

The check, functional test, and calibration minimum frequency for protective instrumentation affecting each of the following protective actions shall be as indicated in the corresponding SR table.

	Protective Action	LCO Table	SR Table
A.	Initiates Reactor Vessel and Containment Isolation	3.2-1	4.2-1
B.	Initiates or Controls HPCI	3.2-2	4.2-2
C.	Initiates or Controls RCIC	3.2-3	4.2-3
D.	Initiates or Controls ADS	3.2-4	4.2-4
E.	Initiates or Controls the LPCI Mode of RHR	3.2-5	4.2-5
F.	Initiates or Controls Core Spray	3.2-6	4.2-6
G.	Initiates Control Rod Blocks	3.2-7	4.2-7
H.	Limits Radioactivity Release	3.2-8	4.2-8
I.	Initiates Recirculation Pump Trip	3.2-9	4.2-9
J.	Monitors Leakage Into the Drywell	3.2-10	4.2-10
K.	Provides Surveillance Information	3.2-11	4.2-11
L.	Initiates Disconnection of Offsite Power Sources	3.2-12	4.2-12
M.	Initiates Energization by Onsite Power Sources	3.2-13	4.2-13
N.	Arms the Low Low Set S/RV System	3.2-14	4.2-14

Table 3.2-1

INSTRUMENTATION WHICH INITIATES REACTOR VESSEL AND PRIMARY CONTAINMENT ISOLATION

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Action to be taken if number of channels is not met for both trip systems (c)	Remarks (d)
1	Reactor Vessel Water Level	Low (Level 3) Narrow Range	2	$\geq$ 8.5 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours or isolate the shutdown cooling system.	Initiates Group 2 & 6 isolation.
		Low Low (Level 2)	2	$\geq$-55 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours.	Starts the SGTS, initiates Group 5 isolation, and initiates secondary containment isolation.
		Low Low Low (Level 1)	2	$\geq$-121.5 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours.	Initiates Group 1 isolation.
2	Reactor Pressure (Shutdown Cooling Mode)	High	1	$\leq$135 psig	Isolate shutdown cooling.	Isolates the shutdown cooling suction valves of the RHR system.
3	Drywell Pressure	High	2	$\leq$ 2 psig	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours	Starts the standby gas treatment system, initiates Group 2 isolation and secondary containment isolation.
4	Main Steam Line Radiation	High	2	$\leq$ 3 times normal full-power background	Initiate an orderly load reduction and close MSIVs within 8 hours	Initiates Group 1 isolation.

Table 3.2-2

INSTRUMENTATION WHICH INITIATES OR CONTROLS HPCI

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low (Level 2)	2	$\geq$ -55 inches	Initiates HPCI; Also initiates RCIC.
2.	Drywell Pressure	High	2	$\leq$ 2 psig	Initiates HPCI; Also initiates LPCI and Core Spray and provides a permissive signal to ADS.
3.	HPCI Turbine Overspeed	Mechanical	1	$\leq$ 5000 rpm	Trips HPCI turbine
4.	HPCI Turbine Exhaust Pressure	High	1	$\leq$ 150 psig	Trips HPCI turbine
5.	HPCI Pump Suction Pressure	Low	1	$\leq$ 15 inches Hg vacuum	Trips HPCI turbine
6.	Reactor Vessel Water level	High (Level 8)	2	$\leq$ +56.5 inches	Trips HPCI turbine
7.	HPCI System Flow (Flow Switch)	High	1	> 800 gpm	Closes HPCI minimum flow bypass line to suppression chamber.
		Low	1	$\leq$ 500 gpm	Opens HPCI minimum flow bypass line if pressure permissive is present.
8.	HPCI Equipment Room	High	1	$\leq$ 175°F	Closes isolation valves in HPCI system, trips HPCI turbine.

Table 3.2-3

INSTRUMENTATION WHICH INITIATES OR CONTROLS RCIC

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low (Level 2)	2	$\geq$-55 inches	Initiates RCIC; also initiates HPCI.
2.	RCIC Turbine Overspeed	Electrical	1	$\leq$110% rated	Trips RCIC turbine.
		Mechanical	1	$\leq$125% rated	Trips RCIC turbine.
3.	RCIC Turbine Exhaust Pressure	High	1	$\leq$+25 psig	Trips RCIC turbine.
4.	RCIC Pump Suction Pressure	Low	1	$\leq$ 15 inches Hg Vacuum	Trips RCIC turbine.
5.	Reactor Vessel Water Level	High (Level 8)	2	$\leq$+56.5 inches	Trips RCIC; automatically resets when water drops below level 8, system automatically restarts at level 2.
6.	RCIC System Flow (Flow Switch)	High	1	>80 gpm	Closes RCIC minimum flow bypass line to suppression chamber.
		Low	1	$\leq$40 gpm	Opens RCIC minimum flow bypass line if pressure permissive is present.
7.	RCIC Equipment Room	High	1	$\leq$175°F	Closes isolation valves in RCIC system, trips RCIC turbine.

Table 3.2-4

INSTRUMENTATION WHICH INITIATES OR CONTROLS ADS

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low (Level 3)	1	≥8.5 inches	Confirms low level, ADS permissive
	Reactor Vessel Water Level	Low Low Low (Level 1)	2	≥-121.5 inches	Permissive signal to ADS timer
2.	Drywell Pressure	High	2	≤2 psig	Permissive signal to ADS timer
3.	RHR Pump Discharge Pressure	High	2	≥100 psig	Permissive signal to ADS timer
4.	CS Pump Discharge Pressure	High	2	≥100 psig	Permissive signal to ADS timer
5.	Auto Depressurization Timer		1	120 ± 12 seconds	With Level 3 and Level 1 and high drywell pressure and CS or RHR pump at pressure, timing sequence begins. If the ADS timer is not reset it will initiate ADS.
6.	Automatic Blowdown Control Power Failure Monitor		1	Not applicable	Monitors availability of power to logic system

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-4 and items in Table 4.2-4.

b. Whenever any CCCS subsystem is required to be operable by Section 3.5, there shall be two operable trip systems. If the required number of operable channels cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip systems is made or found to be inoperable.

Table 3.2-5

INSTRUMENTATION WHICH INITIATES OR CONTROLS THE LPCI MODE OF RHR

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low Low (Level 1)	2	$\geq$ -121.5 inches	Initiates LPCI mode of RHR
2.	Drywell Pressure	High	2	$\leq$ 2 psig	Initiates LPCI mode of RHR
3.	Reactor Vessel Steam Dome Pressure	High (Shutdown Cooling Mode)	1	$\leq$ 135 psig	With primary containment isolation signal, closes RHR (LPCI) inboard motor operated injection valves
		Low	2	$\geq$ 325 psig	Permissive to close Recirculation Discharge Valve and Bypass Valve
		Low	2	$\geq$ 422 psig *	Permissive to open LPCI injection valves
4.	Reactor Water Level (Shroud Level Indicator)		1	$\geq$-203.5 inches	Acts as permissive to divert some LPCI flow to containment spray
5.	LPCI Cross Connect Valve Open Annunciator	N/A	1	Valve not closed	Initiates annunciator when valve is not closed

*This trip function shall be $\leq$500 psig.

Table 3.2-6

INSTRUMENTATION WHICH INITIATES OR CONTROLS CORE SPRAY

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low Low (Level 1)	2	≥-121.5 inches	Initiates CS.
2.	Drywell Pressure	High	2	≤ 2 psig	Initiates CS.
3.	Reactor Vessel Steam Dome Pressure	Low	2	≥ 422 psig*	Permissive to open CS injection valves.
4.	Core Spray Sparger Differential Pressure		1	To be determined during startup testing	Monitors integrity of CS piping inside vessel and core shroud.
5.	CS Pump Discharge Flow (Flow Switch)	Low	1	≥ 475 gpm	Minimum flow bypass line is closed when low flow signal is not present.
6.	Core Spray Pump Discharge Pressure Interlock		2	≥100 psig	Defers ADS actuation until LPCI or CS pump is confirmed to be running
7.	Core Spray Logic Power Failure Monitor		1	Not Applicable	Monitors availability of power to logic system.

*This trip function shall be ≤500 psig.

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-6 and items in Table 4.2-6.

b. Whenever any CCCS subsystem is required to be operable by Section 3.5, there shall be two operable trip systems. If the required number of operable channels cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip system is made or found to be inoperable.

Table 3.2-9

INSTRUMENTATION WHICH INITIATES RECIRCULATION PUMP TRIP

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System	Trip Setting	Remarks
1.	Reactor Vessel Water Level (ATWS RPT)[c]	Low	1[b]	≥ -38 inches	Power must be reduced and the mode switch placed in a mode other than the RUN Mode.
2.	Reactor Pressure (ATWS RPT)	High	1[b]	≤1120 psig	Power must be reduced and the mode switch placed in a mode other than the RUN Mode.
3.	EOC - RPT[d]	1. Turbine Stop Valve Closure 2. Turbine Control Valve Fast Closure	2[e][f]	1. Stop Valve ≤90% Open 2. Control Valve Hydraulic Press Trip Point	Trips recirculation pumps on turbine control valve fast closure or stop valve closure when reactor is > 30%.[e]

(a) The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-9 and items in Table 4.2-9.

(b) Whenever the reactor is in the RUN Mode, there shall be one operable trip system for each parameter for each operating recirculation pump, except that one trip system may remain inoperable for up to 14 days. If this cannot be met, the indicated action shall be taken.

(c) Anticipated Transients Without Scram - Recirculation Pump Trip

(d) End of Cycle - Recirculation Pump Trip

(e) Either of these two EOC - RPT systems can trip both recirculation pumps. Each EOC - RPT system will trip if 2-out-of-2 fast closure signals <u>or</u> 2-out-of-2 stop valve signals are received.

(f) The requirement for these channels applies from EOC-2000 MWD/t to EOC. The RPT system may be placed in an inoperable status for up to 2 hours to provide the required monthly surveillance. If one EOC-RPT system is inoperable for longer than 72 hours or if both EOC-RPT systems are simultaneously inoperable, an orderly power reduction will be immediately initiated and reactor power will be <30% within the next 6 hours.

Table 3.2-11

INSTRUMENTATION WHICH PROVIDES SURVEILLANCE INFORMATION

Ref. No. (a)	Instrument (b)	Required Operable Instrument Channels	Type and Range	Action	Remarks
1	Reactor Vessel Water Level	1	Recorder	(c)	(d)
		2	Indicator 0 to 60"	(c)	(d)
2	Shroud Water Level	1	Recorder	(c)	(d)
		1	Indicator -317" to -17"	(c)	(d)
3	Reactor Pressure	1	Recorder 0 to 1500 psig	(c)	(d)
		2	Indicator 0 to 1200 psig	(c)	(d)
4	Drywell Pressure	2	Recorder -5 to +80 psig	(c)	(d)
5	Drywell Temperature	2	Recorder 0 to 500°F	(c)	(d)
6	Suppression Chamber Air Temperature	2	Recorder 0 to 500°F	(c)	(d)
7	Suppression Chamber Water Temperature	2	Recorder 0 to 250°F	(c)	(d)
8	Suppression Chamber Water Level	2	Indicator 0 to 300"	(c)	(d)
		2	Recorder 0 to 30"	(c)(e)	(d)
9	Suppression Chamber Pressure	2	Recorder -5 to +80 psig	(c)	(d)
10	Rod Position Information System (RPIS)	1	28 Volt Indicating Lights	(c)	(d)
11	Hydrogen and Oxygen Analyzer	1	Recorder 0 to 52	(c)	(d)
12	Post LOCA Radiation Monitoring System	1	Recorder	(c)	(d)
			Indicator 1 to 10^6 R/hr	(c)	(d)
13	a) Safety/Relief Valve Position Primary Indicator	1/SRV	Indicating Light at 85 psig	(f)	
	b) Safety/Relief Valve Position Secondary Indicator	1	Recorder 0 to 600°F	(f)	

Table 3.2-14

INSTRUMENTATION WHICH ARMS LOW LOW SET S/RV SYSTEM

Ref No.[a]	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System	Trip Setting	Remarks
1.	Reactor Vessel Steam Dome Pressure	High	2[b]	≤ 1054 psig	
2.	Relief/Safety Valve Tailpipe Pressure	High	2/valve	85, +15, -5 psig	The limiting condition of operation of these switches is provided in Specification 3.6.H.1

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in table 3.2-14 and items in table 4.2-14.

b. With the requirements for the minimum number of OPERABLE channels not satisfied for one trip system, place the inoperable channel in the tripped condition or declare the associated system inoperable within one hour. With the requirements for the minimum number of OPERABLE channels not satisfied for both trip systems, declare the associated system inoperable within one hour.

Table 4.2-1

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation
Which Initiates Reactor Vessel and Primary Containment Isolation

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Levels 1, 2, and 3)	Once/shift	Once/month	Once/operating cycle
2	Reactor Pressure (Shutdown Cooling Mode)	None	(d)	Every 3 months
3	Drywell Pressure	None	(d)	Every 3 months
4	Main Steam Line Radiation	None	Once/week (e)	Every 3 months (f)
5	Main Steam Line Pressure	None	(d)	Every 3 months
6	Main Steam Line Flow	None	(d)	Every 3 months
7	Main Steam Line Tunnel Temperature	None	Once/operating cycle	Once/operating cycle
8	Reactor Water Cleanup System Differential Flow	None	(d)	Every 3 months
9	Reactor Water Cleanup Equipment Room Temperature	None	(d)	Every 3 months

Table 4.2-2

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls HPCI

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 2)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	None	(d)	Every 3 months
3	HPCI Turbine Overspeed	None	N/A	Once/operating cycle
4	HPCI Turbine Exhaust Pressure	None	(d)	Every 3 months
5	HPCI Pump Suction Pressure	None	(d)	Every 3 months
6	Reactor Vessel Water Level (Level 8)	Once/shift	Once/month	Once/operating cycle
7	HPCI System Flow (Flow Switch)	None	(d)	Every 3 months
8	HPCI Equipment Room	None	(d)	Every 3 months
9	deleted			
10	HPCI Steam Line Pressure	None	(d)	Every 3 months

Table 4.2-3

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls RCIC

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 2)	Once/shift	Once/month	Once/operating cycle
2	RCIC Turbine Overspeed			
	Electrical/	None	N/A	Once/operating cycle
	Mechanical	None	N/A	Once/operating cycle
3	RCIC Turbine Exhaust Pressure	None	(d)	Every 3 months
4	RCIC Pump Suction Pressure	None	(d)	Every 3 months
5	Reactor Vessel Water Level (Level 8)	Once/shift	Once/month	Once/operating cycle
6	RCIC System Flow (Flow Switch)	None	(d)	Every 3 months
7	RCIC Equipment Room	None	(d)	Every 3 months
8	deleted			
9	RCIC Steam Line Pressure	None	(d)	Every 3 months

Table 4.2-4

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls ADS

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 3)	Once/shift	Once/month	Once/operating cycle
	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	None	(d)	Every 3 months
3	RHR Pump Discharge Pressure	None	(d)	Every 3 months
4	CS Pump Discharge Pressure	None	(d)	Every 3 months
5	Auto Depressurization Timer	None	N/A	Once/operating cycle
6	Automatic Blowdown Control Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-4

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-4 and items in Table 3.2-4.

Table 4.2-5

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation
Which Initiates or Controls the LPCI Mode of RHR

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	None	(d)	Every 3 months
3	Reactor Vessel Steam Dome Pressure	Once/shift	Once/month	Once/operating cycle
4	Reactor Water Level (Shroud Level Indicator)	Once/ day	(d)	Every 3 months
5	LPCI Cross Connect Valve Open Annunciator	None	Once/Operating cycle	None
6	RHR (LPCI) Pump Discharge Pressure Interlock	None	(d)	Every 3 months
7	RHR (LPCI) Pump Flow (Flow Switch)	None	(d)	Every 3 months
8	RHR (LPCI) Pump Start Timers	None	N/A	Once/operating cycle
9	Valve Selection Timers	None	N/A	Once/operating cycle
10	RHR Relay Logic Power Failure Monitor	None	Once/operating cycle	None

Table 4.2-6

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls Core Spray

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	None	(d)	Every 3 months
3	Reactor Vessel Steam Dome Pressure	Once/shift	Once/month	Once/operating cycle
4	Core Spray Sparger Differential Pressure	Once/day	N/A	Once/operating cycle
5	CS Pump Discharge Flow (Flow Switch)	None	(d)	Every 3 months
6	Core Spray Pump Discharge Pressure Interlock	None	(d)	Every 3 months
7	Core Spray Logic Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-6

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-6 and items in Table 3.2-6.

Table 4.2-9

CHECK AND CALIBRATION MINIMUM FREQUENCY FOR INSTRUMENTATION
WHICH INITIATES RECIRCULATION PUMP TRIP

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency	Instrument Calibration Minimum Frequency
1	Reactor Vessel Water Level (ATWS RPT)[b]	Once/day	Once/operating cycle	Once/operating cycle
2	Reactor Pressure (ATWS RPT)	None	Once/operating cycle	Once/operating cycle
3	EOC - RPT Trip			
	a) Initiating Logic	None	Once/month	None
	b) Breakers	None	Once/operating cycle	None
	c) Response Time RPT logics + Breakers	None	None	Once/operating cycle

Notes for Table 4.2-9

(a) The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-9 and items in Table 4.2-9.

(b) An ATWS recirculation pump trip logic system functional test shall be performed once per operating cycle.

Table 4.2-14

CHECK, FUNCTIONAL TEST, AND CALIBRATION MINIMUM FREQUENCY FOR INSTRUMENTATION
WHICH ARMS THE LOW LOW SET S/RV SYSTEM

Ref No.[a]	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency[b]	Instrument Calibration Minimum Frequency[c]
1	Reactor Vessel Steam Dome Pressure	Once/shift	Once/month	Once/operating cycle
2	Relief/Safety Valve Tailpipe Pressure	N/A	Once/month(d)	Once/operating cycle(e)

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in table 4.2-14 and items in table 3.2-14.

b. Instrument functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.

c. Calibrations are not required when the instruments are not required to be operable. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.

d. See section 4.6.H.1.e.1 for exceptions to this pressure switch functional test frequency.

e. See section 4.6.H.1.e.2.

3.2 PROTECTIVE INSTRUMENTATION

In addition to the Reactor Protection System (RPS) instrumentation which initiates a reactor scram, protective instrumentation has been provided which initiates action to mitigate the consequences of accidents which are beyond the operators ability to control, or terminates operator errors before they result in serious consequences. This set of Specifications provides the limiting conditions for operation of the instrumentation:
(a) which initiates reactor vessel and primary containment isolation,
(b) which initiates or controls the core and containment cooling systems,
(c) which initiates control rod blocks, (d) which initiates protective action,
(e) which monitors leakage into the drywell and (f) which provides surveillance information. The objectives of these specifications are (i) to assure the effectiveness of the protective instrumentation when required by preserving its capability to tolerate a single failure of any component of such systems even during periods when portions of such systems are out of service for maintenance, and (ii) to prescribe the trip settings required to assure adequate performance. When necessary, one channel may be made inoperable for brief intervals to conduct required functional tests and calibrations.

A. Instrumentation Which Initiates Reactor Vessel and Primary Containment Isolation (Table 3.2-1)

Isolation valves are installed in those lines which penetrate the primary containment and must be isolated during a loss of coolant accident so that the radiation dose limits are not exceeded during an accident condition. Actuation of these valves is initiated by protective instrumentation shown in Table 3.2-1 which senses the conditions for which isolation is required. Such instrumentation must be available whenever primary containment integrity is required. The objective is to isolate the primary containment so that the guidelines of 10 CFR 100 are not exceeded during an accident. The events when isolation is required are discussed in Appendix G of the FSAR. The instrumentation which initiates primary system isolation is connected in a dual bus arrangement.

1. Reactor Vessel Water Level

a. Reactor Vessel Water Level Low (Level 3) (Narrow Range)

The reactor water level instrumentation is set to trip when reactor water level is approximately 14 feet above the top of the active fuel. This level is referred to as Level 3 in the Technical Specifications and corresponds to a reading of 8.5 inches on the Narrow Range Scale. This trip initiates Group 2 and 6 isolation but does not trip the recirculation pumps.

b. Reactor Vessel Water Level Low Low (Level 2)

The reactor water level instrumentation is set to trip when reactor water level is approximately 8 feet above the top of the active fuel. This level is referred to as Level 2 in the Technical Specifications and corresponds to a reading of -55 inches.
This trip initiates Group 5 isolation, starts the standby gas treatment system, and initiates secondary containment isolation.

3.2.A.1.c. Reactor Vessel Water Level Low Low Low (Level 1)

The reactor water level instrumentation is set to trip when the reactor water level is approximately 43 inches above the top of the active fuel. This level is referred to as Level 1 in the Technical Specifications and corresponds to a reading of -121.5 inches. This trip initiates Group 1 isolation.

3.2.A.7 Main Steam Line Tunnel Temperature High (Continued)

with the resultant small release of radioactivity, gives isolation before the guidelines of 10 CFR 100 are exceeded.

8. Reactor Water Cleanup System Differential Flow High

Gross leakage (pipe break) from the reactor water cleanup system is detected by measuring the difference of flow entering and leaving the system. The set point is low enough to ensure prompt isolation of the cleanup system in the event of such a break but, not so low that spurious isolation can occur due to normal system flow fluctuations and instrument noise. Time delay relays are used to prevent the isolation signal which might be generated from the initial flow surge when the cleanup system is started or when operational system adjustments are made which produce short term transients.

9. Reactor Water Cleanup Equipment Room Temperature High and

10. Reactor Water Cleanup Equipment Room Differential Temperature High

Leakage in the high temperature process flow of the reactor water cleanup system external to the primary containment will be detected by temperature sensing elements. Temperature sensors are located in the inlet and outlet ventilation ducts to measure the temperature difference. Local ambient temperature sensors are located in the compartment containing equipment and piping for this system. An alarm in the main control room will be set to annunciate a temperature rise corresponding to a leakage within the identified limit. In addition to annunciation, a high cleanup room temperature will actuate automatic isolation of the cleanup system.

11. Condenser Vacuum Low

The Bases for Condenser Vacuum Low are discussed in The Bases for Specification 2.1.A.7.

B. Instrumentation Which Initiates or Controls HPCI (Table 3.2-2)

1. Reactor Vessel Water Level Low Low (Level 2)

The reactor vessel water level instrumentation setpoint which initiates HPCI is ≥ -55 inches. This level is approximately 8 feet above the top of the active fuel and in the Technical Specifications is referred to as Level 2. The reactor vessel low water level setting for HPCI system initiation is selected high enough above the active fuel to start the HPCI system in time both to prevent excessive fuel clad temperatures and to prevent more than a small fraction of the core from reaching the temperature at which gross fuel failure occurs. The water level setting is far enough below normal levels that spurious HPCI system startups are avoided.

2. Drywell Pressure High

The drywell pressure instrumentation setpoint with initiates HPCI is ≤ 2 psig. High drywell pressure is indicative of a failure of the nuclear system process barrier. This pressure is selected to be as low as possible without inducing spurious HPCI system startups. This instrumentation serves as a backup to the water level instrumentation described above.

3.2.B.3 HPCI Turbine Overspeed

The HPCI turbine is automatically shut down by tripping the HPCI turbine stop valve closed when the 5000 rpm setpoint on the mechanical governor is reached. A turbine overspeed trip is required to protect the physical integrity of the turbine.

4. HPCI Turbine Exhaust Pressure High

When HPCI turbine exhaust pressure reaches the setpoint (≤ 150 psig) the HPCI turbine is automatically shut down by tripping the HPCI stop valve closed. HPCI turbine exhaust high pressure is indicative of a condition which threatens the physical integrity of the exhaust line.

5. HPCI Pump Suction Pressure Low

A pressure switch is used to detect HPCI system pump suction pressure and is set to trip the HPCI turbine at 15 inches of mercury vacuum. This setpoint is chosen to prevent pump damage by cavitation.

6. Reactor Vessel Water Level High (Level 8)

A reactor water level of +56.5 inches is indicative that the HPCI system has performed satisfactorily in providing makeup water to the reactor vessel. The reactor vessel high water level setting which trips the HPCI turbine is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the HPCI turbine. Two analog differential pressure transmitters trip to initiate a HPCI turbine shutdown.

7. HPCI System Flow

To prevent damage by overheating at reduced HPCI system pump flow, a pump discharge minimum flow bypass is provided. The bypass is controlled by an automatic, D. C. motor-operated valve. A high flow signal from a flow meter downstream of the pump on the main HPCI line will cause the bypass valve to close. Two signals are required to open the valve: A HPCI pump discharge pressure switch high pressure signal must be received to act as a permissive to open the bypass valve in the presence of a low flow signal from the flow switch.

NOTE:

Because the steam supply line to the HPCI turbine is part of the nuclear system process barrier, the following conditions (8-13) automatically isolate this line, causing shutdown of the HPCI system turbine.

8. HPCI Equipment Room Temperature High

High ambient temperature in the HPCI equipment room near the emergency area cooler could indicate a break in the HPCI system turbine steam line. The automatic closure of the HPCI steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. The high

3.2.B.13 Suppression Chamber Area Differential Air Temperature High

As for the HPCI equipment room differential temperature, and for the same reason, a differential air temperature greater than the trip setting of ≤ 42°F between the inlet and outlet ducts which ventilate the suppression chamber area will initiate a timer to isolate the HPCI turbine steam line.

14. Condensate Storage Tank Level Low

The CST is the preferred source of suction for HPCI. In order to provide an adequate water supply, an indication of low level in the CST automatically switches the suction to the suppression chamber. A trip setting of 0 inches corresponds to 10,000 gallons of water remaining in the tank.

15. Suppression Chamber Water Level High

A high water level in the suppression chamber automatically switches HPCI suction to the suppression chamber from the CST.

16. HPCI Logic Power Failure Monitor

The HPCI Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

C. Instrumentation Which Initiates or Controls RCIC (Table 3.2-3)

1. Reactor Vessel Water Level Low Low (Level 2)

The reactor water level instrumentation setpoint which initiates RCIC is ≥ -55 inches. This level is approximately 8 feet above the top of the active fuel and is referred to as Level 2. This setpoint insures that RCIC is started in time to preclude conditions which lead to inadequate core cooling.

2. RCIC Turbine Overspeed

The RCIC turbine is automatically shutdown by tripping the RCIC turbine stop valve closed when the 125% speed at rated flow setpoint on the mechanical governor is reached. Turbine overspeed is indicative of a condition which threatens the physical integrity of the system. An electrical tachometer trip setpoint of 110% also will trip the RCIC turbine stop valve closed.

3. RCIC Turbine Exhaust Pressure High

When RCIC turbine exhaust pressure reaches the setpoint (≤ 25 psig), the RCIC turbine is automatically shut down by tripping the RCIC turbine stop valve closed. RCIC turbine exhaust high pressure is indicative of a condition which threatens the physical integrity of the exhaust line.

4. RCIC Pump Suction Pressure Low

One pressure switch is used to detect low RCIC system pump suction pressure and is set to trip the RCIC turbine at ≤ 15 inches of mercury vacuum. This setpoint is choosen to prevent pump damage by cavitation.

3.2.C.5 Reactor Vessel Water Level High (Level 8)

A high reactor water level trip is indicative that the RCIC system has performed satisfactorily in providing makeup water to the reactor vessel. The reactor vessel high water level setting which trips the RCIC turbine is near the top of the steam separators and sufficiently low to prevent gross moisture carryover to the RCIC turbine. Two differential pressure transmitters trip to initiate a RCIC turbine shutdown. Once tripped the system is capable of automatic reset after the water level drops below Level 8. This automatic reset eliminates the need for manual reset of the system before the operator can take manual control to avoid fluctuating water levels.

6. RCIC System Flow

To prevent damage by overheating at reduced RCIC system pump flow, a pump discharge minimum flow bypass is provided. The bypass is controlled by an automatic, D. C. motor-operated valve. A high flow signal from a flow meter downstream of the pump on the main RCIC line will cause the bypass valve to close. Two signals are required to open the valve: A RCIC pump discharge pressure switch high pressure signal must be received to act as a permissive to open the bypass valve in the presence of a low flow signal from the flow switch.

Note:

Because the steam supply line to the RCIC turbine is part of the nuclear system process barrier, the following conditions (7 - 13) automatically isolate this line, causing shutdown of the RCIC system turbine.

7. RCIC Equipment Room Temperature High

High ambient temperature in the RCIC equipment room near the emergency area cooler could indicate a break in the RCIC system turbine steam line. The automatic closure of the RCIC steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. The high temperature setting of 90 F + ambient was selected to be far enough above anticipated normal RCIC system operational levels to avoid spurious isolation but low enough to provide timely detection of a RCIC turbine steam line break. The high temperature trip initiates a timer which isolates the RCIC turbine steam line if the temperature is not reduced below the setpoint.

8. RCIC Steam Line Pressure Low

Low pressure in the RCIC steam supply could indicate a break in the RCIC steam line. Therefore, the RCIC steam line isolation valves are automatically closed. The steam line low pressure function is provided so that in the event a gross rupture of the RCIC steam line occurred upstream from the high flow sensing location, thus negating the high flow indicating function, isolation would be effected on low pressure. The iso-

D. Instrumentation Which Initiates or Controls ADS (Table 3.2-4)

The ADS is a backup system to HPCI. In the event of its failure to maintain reactor water level, ADS will initiate depressurization of the reactor in time for LPCI and CS to adequately cool the core. Four signals are required to initiate ADS: Low water level, confirmed low water level, high drywell pressure, and either a RHR or Core Spray pump available. The simultaneous presence of these four signals will initiate a 120 second timer which will depressurize the reactor if not reset.

1. Reactor Vessel Water Level

a. Reactor Vessel Water Level Low (Level 3)

The second reactor vessel low water level initiation setting (+8.5 inches) is selected to confirm that water level in the vessel is in fact low, thus providing protection against inadvertent depressurization in the event of an instrument line (water level) failure. Such a failure could produce a simultaneous high drywell pressure. A confirmed low level is one of four signals required to initiate ADS.

b. Reactor Vessel Water Level Low Low Low (Level 1)

The reactor vessel low water level setting of -121.5 inches is selected to provide a permissive signal to open the relief valve and depressurize the reactor vessel in time to allow adequate cooling of the fuel by the core spray and LPCI systems following a LOCA in which the other make up systems (RCIC and HPCI) fail to maintain vessel water level. This signal is one of four required to initiate ADS.

2. Drywell Pressure High

A primary containment high pressure of ≥ 2 psig indicates that a breach of the nuclear system process barrier has occurred inside the drywell. The signal is one of four required to initiate the ADS.

3.2.D. 3. RHR Pump Discharge Pressure High

An RHR pump discharge pressure of ≥ 100 psig indicates that LPCI flow is available when the reactor is depressurized. The presence of this signal means low pressure core standby cooling is available. Low pressure core standby cooling available is one of the four signals required to initiate ADS.

4. Core Spray Pump Discharge Pressure High

A core spray pump discharge pressure of ≥ 100 psig indicates that Core Spray flow is available when the reactor is depressurized. The presence of this signal means low pressure core standby cooling is available. Low pressure core standby cooling available is one of the four signals required to initiate ADS.

5. Auto Depressurization Timer

The 120-second delay time setting is chosen to be long enough so that the HPCI system has time to start, yet not so long that the core spray system and LPCI are unable to adequately cool the core if HPCI fails to start. An alarm in the main control room is annunciated each time either of the timers is timing. Resetting the automatic depressurization system logic in the presence of tripped initiating signals recycles the timers.

6. Automatic Blowdown Control Power Failure Monitor

The Automatic Blowdown Control Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

E. Instrumentation Which Initiates or Controls the LPCI Mode of RHR (Table 3.2-5)

1. Reactor Vessel Water Level Low Low Low (Level 1)

Reactor vessel low water level (Level 1) initiates LPCI and indicates that the core is in danger of being overheated because of an insufficient coolant inventory. This level is sufficient to allow the timed initiation of the various valve closure and loop selection routines to go to completion and still successfully perform its design function.

2. Drywell Pressure High

Primary containment high pressure is indicative of a break in the nuclear system process barrier inside the drywell. The high drywell pressure setpoint of ≤ 2 psig is selected to be high enough to avoid spurious starts but low enough to allow timely system initiation.

3. Reactor Vessel Steam Dome Pressure Low

The Bases for Reactor Pressure (Shutdown Cooling Mode) are discussed in the Bases for Specification 3.2.A.2.

With an analytical limit of ≥ 300 psig and a nominal trip setpoint of 360 psig, the recirculation discharge valve will close successfully during a LOCA condition.

Once the LPCI system is initiated, a reactor low pressure setpoint of 422 psig produces a signal which is used as a permissive to open the LPCI in-

3.2.E.9 Valve Selection Timers

After 10 minutes, a timer cancels the LPCI signals to the injection valves. The cancellation of the signals allows the operator to divert the water for other post-accident purposes. Cancellation of the signals does not cause the injection valves to move.

10. RHR Relay Logic Power Failure Monitor

The RHR Relay Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

F. Instrumentation Which Initiates or Controls Core Spray (Table 3.2-6)

1. Reactor Vessel Water Level Low Low Low (Level 1)

A reactor low water level of -121.5 inches (Level 1) initiates Core Spray. This level is indicative that the core is in danger of being overheated because of an insufficient coolant inventory.

2. Drywell Pressure High

Primary containment high pressure is indicative of a break in the nuclear system process barrier inside the drywell. The high drywell pressure setpoint of ≤ 2 psig is selected to be high enough to avoid spurious system initiation but low enough to allow timely system initiation.

3. Reactor Vessel Steam Dome Pressure Low

Once the core spray system is initiated, a reactor low pressure setpoint of 422 psig produces a signal which is used as a permissive to open the core spray injection valves. The valves do not open, however, until reactor pressure falls below the discharge head of the core spray system.

4. Core Spray Sparger Differential Pressure

A detection system is provided to continuously confirm the integrity of the core spray piping between the inside of the reactor vessel and the core shroud. A differential pressure switch measures the pressure difference between the top of the core support plate and the inside of the core spray sparger pipe just outside the reactor vessel. If the core spray sparger piping is sound, this pressure difference will be the pressure drop across the core resulting from inter-channel leakage. If integrity is lost, this pressure drop will include the steam separator pressure drop. An increase in the normal pressure drop initiates an alarm in the main control room.

M. Instrumentation Which Initiates Energization by Onsite Power Sources (Table 3.2-13)

The undervoltage relays shall automatically trip the loss of offsite power (LOSP) lockout relays if voltage is lost on the emergency buses and low voltage is sensed on start-up transformer 1C (SUT 1C). This lockout will, if a loss of coolant accident (LOCA) has previously occurred, cause energization of the emergency 4160 volt buses by the Diesel Generators (D/Gs). If the LOSP and LOCA occur simultaneously, the lockout relay will provide a permissive allowing D/G output breaker closure when the D/G voltage is up to normal. The undervoltage relays will have no time delay. The absence of time delay provides a faster response time if the diesel generator has been previously initiated and prevents an additional time delay if it has not. This scheme prevents the connection of the D/G to the offsite power source.

N. Instrumentation Which Arms Low Low Set System (Table 3.2-14)

The bases for these trip functions are found in the bases for Section 3.6.H, page 3.6-21.

3.2.1 References

1. FSAR Appendix G, Plant Nuclear Safety Operational Analysis
2. FSAR Section 7.3, Primary Containment and Reactor Vessel Isolation Control System
3. FSAR Section 14, Plant Safety Analysis
4. FSAR Section 6, Core Standby Cooling Systems
5. FSAR Section 14.4.4, Refueling Accident
6. FSAR Section 6.5.3, Integrated Operation of the Core Standby Cooling Systems
7. FSAR Section 6.5.3.1, Liquid Line Breaks
8. 10 CFR 100

4.2 PROTECTIVE INSTRUMENTATION

The instrumentation listed in Tables 4.2-1 thru 4.2-13 will be functionally tested and calibrated at regularly scheduled intervals. The same design reliability goal as the Reactor Protection System of 0.99999 is generally applied for all applications of one-out-of-two-taken-twice logic. Therefore, on-off sensors are tested once every three months, and bi-stable trips associated with analog sensors and amplifiers are tested once per week. The ATTS instruments are tested once per month per NEDO-21617-A.

Those instruments which, when tripped, result in a rod block have their contacts arranged in a one-out-of-n logic, and all are capable of being bypassed. For such a tripping arrangement with bypass capability provided, there is an optimum test interval that should be maintained in order to maximize the reliability of a given channel (Reference 1). This takes account of the fact that testing degrades reliability and the optimum interval between tests is approximately given by:

$$i = \sqrt{\frac{2t}{r}}$$

Where: i = the optimum interval between tests.

t = the time the trip contacts are disabled from performing their function while the test is in progress.

r = the expected failure rate of the relays.

To test the trip relays requires that the channel be bypassed, the test made, and the system returned to its initial state. It is assumed this task requires an estimated 30 minutes to complete in a thorough and workmanlike manner and that the relays have a failure rate of 10^{-6} failures per hour. Using this data and the above operation, the optimum test interval is:

$$i = \sqrt{\frac{2(0.5)}{10^{-6}}} = 10^{3} \text{ hours} \approx 42 \text{ days}$$

A test interval of once-per-month will be used initially.

The sensors and electronic apparatus have not been included here as these are analog devises with readouts in the control room and the sensors and electronic apparatus can be checked by comparison with other like instruments. The checks which are made on a daily or once per shift basis are adequate to assure operability of the sensors and electronic apparatus, and the test interval given above provides for optimum testing of the relay circuits.

The above calculated test interval optimizes each individual channel, considering it to be independent of all others. As an example, assume that there are two channels with an individual technician assigned to each. Each technician tests his channel at the optimum frequency, but the two technicians are not allowed to communicate so that one can advise the other that his channel is under test. Under these conditions, it is possbile for both channels to be under test simultaneously. Now, assume that the technicians are required to communicate and that two

3.6.H.1. Relief/Safety Valves

a. When one or more relief/safety valve(s) is known to be failed an orderly shutdown shall be initiated and the reactor depressurized to less than 113 psig within 24 hours. Prior to reactor startup from a cold condition all relief/safety valves shall be operable.

b. With one or more relief/safety valve(s) stuck open, place the reactor mode switch in the shutdown position.

c. With one or more safety/relief valve tailpipe pressure switches of a safety/relief valve declared inoperable and the associated safety/relief valve(s) otherwise indicated to be open, place the reactor mode switch in the Shutdown position.

d. With one safety/relief valve tailpipe pressure switch of a safety/relief valve declared inoperable and the associated safety/relief valve(s) otherwise indicated to be closed, plant operation may continue. Remove the function of that pressure switch from the low low set logic circuitry until the next COLD SHUTDOWN. Upon COLD SHUTDOWN, restore the pressure switch(es) to OPERABLE status before STARTUP.

e. With both safety/relief valve tailpipe pressure switches of a safety/relief valve declared inoperable and the associated safety/relief valve(s) otherwise indicated to be closed, restore at least one inoperable switch to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4.6.H.1. Relief/Safety Valves

a. End of Operating Cycle

Approximately one-half of all relief/safety valves shall be benchchecked or replaced with a benchchecked valve each refueling outage. All 11 valves will have been checked or replaced upon the completion of every second operating cycle.

b. Each Operating Cycle

Once during each operating cycle, at a reactor pressure > 100 psig each relief valve shall be manually opened until thermocouples downstream of the valve indicate steam is flowing from the valve.

c. Integrity of Relief Valve Bellows*

The integrity of the relief bellows shall be continuously monitored and the pressure switch calibrated once per operating cycle and the accumulators and air piping shall be inspected for leakage once per operating cycle.

d. Relief Valve Maintenance

At lease one relief valve shall be dissassembled and inspected each operating cycle.

e. Operability of Tail Pipe Pressure Switches

The tail pipe pressure switch of each relief/safety valve shall be demonstrated operable by performance of a:

1. Functional Test:

   a. At least once per 31 days, except that all portions of instrumentation inside the primary containment may be excluded from the functional text, and

*Does not apply to two-stage Target Rock SRVs

4.6.H.1 Relief/Safety Valves (Continued)

e. Operability of Tail Pipe Pressure Switches

1. Functional Test:

b. At each scheduled outage greater than 72 hours during which entry is made into the primary containment, if not performed within the previous 31 days.

2. Calibration and verifying the setpoint to be 85, +15, -5 psig at least once per 18 months.

3.6.H.2 Relief/Safety Valves Low Low Set Function

During power operation startup, and hot standby, the relief valve function and the low low set function of the following reactor coolant system safety/relief valves shall be OPERABLE with the following low low set function lift settings:

Low Low Set Valve Function	Allowable Value (psig)* Open	Close
Low	≤ 1005	≤ 857
Medium	≤ 1020	≤ 872
Medium High	≤ 1035	≤ 887
High	≤ 1045	≤ 897

a. With the relief valve function and/or the low low set function of one of the above required reactor coolant system safety/relief valves inoperable, restore the relief valve function and the low low set function to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and COLD SHUTDOWN within the following 24 hours.

4.6.H.2 Relief/Safety Valves Low Low Set Function

The low low set relief valve function and the low low set function pressure actuation instrumentation shall be demonstrated OPERABLE by performance of a:

a. CHANNEL FUNCTIONAL TEST, including calibration of the trip unit and the dedicated high steam dome pressure channels**, at least once per month.

b. CHANNEL CALIBRATION, Logic System Functional Test, and simulated automatic operation of the entire system at least once per 18 months.

* The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

** The setpoint for dedicated high steam dome pressure changels is ≤ 1054 psig.

b. With the relief valve function and/or the low low set function of more than one of the above required reactor coolant system relief/safety valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3.6.I Jet Pumps

Whenever the reactor is in the Start & Hot Standby or Run Mode with both recirculating pumps operating, all jet pumps shall be operable. If it is determined that a jet pump is inoperable, an orderly shutdown shall be initiated and the reactor shall be in the Cold Shutdown Condition with in 24 hours.

I. Jet Pumps

Whenever both recirculating pumps are operating with the reactor in the Start & Hot Standby or Run Mode, jet pump operability shall be checked daily by verifying that the following conditions do not occur simultaneously.

1. The two recirculation loops have a flow imbalance of 15% or more when the pumps are operated at the same speed.

3.6.H. Relief/Safety Valves (Continued)

Experience in relief/safety valve operation shows that a testing of 50 percent of the valves per year is adequate to detect failure or deteriorations. The relief/safety valves are benchtested every second operating cycle to ensure that their set points are within the tolerance given in Specification 2.2.A. The relief/safety valves are tested in place at low reactor pressure once per operating cycle to establish that they will open and pass steam.

The requirements established above apply when the nuclear system can be pressurized above ambient conditions. These requirements are applicable at nuclear system pressures below normal operating pressures because abnormal operational transients could possibly start at these conditions such that eventual overpressure relief would be needed. However, these transients are much less severe in terms of pressure, than those starting at rated conditions. The valves need not be functional when the vessel head is removed, since the nuclear system cannot be pressurized.

The low low set (LLS) system lowers the opening and closing setpoints on four preselected relief/safety valves. The LLS system lowers the setpoints after any relief/safety valve has opened at its normal steam pilot setpoint when a concurrent high reactor vessel steam dome pressure scram signal is present. The purpose of the LLS is to mitigate the induced high frequency loads on the containment and thrust loads on the SRV discharge line. The LLS system increases the amount of reactor depressurization during a relief/safety valve blowdown because the lowered LLS setpoints keep the four selected LLS relief/safety valves open for a longer time. The high reactor vessel steam dome pressure signal for the LLS logic is provided by the exclusive analog trip channels. The purpose of installing special dedicated steam dome pressure channels is to maintain separation from the RPS high pressure scram functions.

I. Jet Pumps

Failure of a jet pump nozzle assembly hold down mechanism, nozzle assembly and/or riser, would increase the cross-sectional flow area for blowdown following the design basis double-ended line break. Therefore, if a failure occurred, repairs must be made.

The detection technique is as follows. With the two recirculation pumps balanced in speed to within ± 5%, the flow rates in both recirculation loops will be verified by control room monitoring instruments. If the two flow rate values do not differ by more than 10%, riser and nozzle assembly integrity has been verified. If they do differ by 10% or more, the core flow rate measured by the jet pump diffuser differential pressure system must be checked against the core flow rate derived from the measured values of loop flow to core flow correlation. If the difference between measured and derived core flow rate is 10% or more (with the derived value higher) diffuser measurements will be taken to define the location within the vessel of failed jet pump nozzle (or riser) and the plant shut down for repairs.

3.6.I. Jet Pumps (Continued)

If the potential blowdown flow area is increased, the system resistance to the recirculation pump is also reduced; hence, the affected drive pump will "run out" to a substantitally higher flow rate (approximately 115% to 120% for a single nozzle failure). If the two loops are balanced in flow at the same speed, the resistance characteristics cannot have changed. Any imbalance between drive loop flow rates would be indicated by the plant process instrumentation. In addition, the affected jet pump would provide a leakage path past the core thus reducing the core flow rate. The reverse flow through the inactive jet pump would still be indicated by a positive differential pressure but the net effect would be a light decrease (3% to 6%) in the total core flow measured. This decrease, together with the loop flow increase would result in a lack of correlation between measured and derived core flow rate. Finally, the affected jet pump diffuser differential pressure signal would be reduced because the backflow would be less than the normal forward flow.

A nozzle-riser system failure could also generate the coincident failure of a jet pump body; however, the converse is not true. The lack of any substantial stress in the jet pump body makes failure impossible without an initial nozzle riser system failure.

3.6.J Recirculation Pump Speeds

An evaluation was not provided for ECCS performance during reactor operation with one recirculation loop out-of-service. Therefore, continuous reactor operation under such conditions should not be permitted until the necessary analyses have been performed, evaluated and determined acceptable. The reactor may, however, operate for periods up to 24 hours with one recirculation loop out-of-service. This short time period permits corrective action to be taken and minimizes unnecessary shutdowns which is consistent with other Technical Specifications. During this period of time the reactor will be operated within the restrictions of the thermal analysis and will be protected from fuel damage resulting from anticipated transients.

TABLE 3.7-1

PRIMARY CONTAINMENT ISOLATION VALVES

Isolation Group (b)	Valve Identification (d)	Number of Power Operated Valves Inside	Outside	Maximum Operating Time (sec)	Normal Position (a)	Action on Initiating Signal (a)
2	Suppression chamber exhaust valve bypass to standby gas treatment (T48-F339, T48-F338)		2	5	C	SC
2	Suppression chamber nitrogen make-up line (normal operation) (T48-F118B)		1	5	0	GC
2	Drywell and suppression chamber nitrogen supply line (inerting) (T48-F103)		1	5	C	SC
2	Drywell and suppression chamber nitrogen make-up line (normal operation) (T48-F104)		1	5	C	SC
2	Drywell equipment drain sump discharge (G11-F019, G11-F020)		2	15	C	SC
2	Drywell floor drain sump discharge (G11-F003, G11-F004)		2	15	C	SC
2	TIP Guide Tube (C51-J004)		1 each line	NA	C	SC
(c)	Drywell pneumatic system (P70-F002, P70-F003)		2	5	0	GC
6	RHR reactor shutdown cooling suction (supply) (E11-F008, E11-F009)	1	1	24	C	SC

TABLE 3.7-1 (Cont'd)

PRIMARY CONTAINMENT ISOLATION VALVES

Isolation Group (b)	Valve Identification (d)	Number of Power Operated Valves Inside	Number of Power Operated Valves Outside	Maximum Operating Time (sec)	Normal Position (a)	Action on Initiating Signal (a)
6	RHR reactor head spray (E11-F022, E11-F023)	1	1	20	C	SC
3	HPCI - turbine steam (E41-F002, E41-F003)	1	1	50	0	GC
4	RCIC - turbine steam (E51-F007, E51-F008)	1	1	20	0	GC
5	Reactor water cleanup from recirculation loop (G31-F001, G31-F004)	1	1	30	0	GC

(e)	Check Valve Identification	Number of Valves Inside	Number of Valves Outside	(e)	Normal Position	(e)
	Feedwater (B21-F010 A,B; B21-F032A,B)	2	2		0	
	Control Rod Hydraulic Return (C11-F083, C11-F086)	1	1		0	
	Standby Liquid Control System (C41-F007, C41-F006)	1	1		C	
	Reactor water cleanup return line (G31-F039)		1		0	
	RHR injection testable check (E11-F050 A,B)	2			C	

Table 3.7-1
(Concluded)

Primary Containment Isolation Valves

These notes refer to the lower case letters in parentheses on the previous page.

NOTES:

a. Key: O = Open SC = Stays closed
C = Closed GC = Goes closed

b. Isolation Groupings are as follows:

GROUP 1: The valves in Group 1 are actuated by any one of the following conditions:

1. Reactor vessel water level Low Low Low (Level 1)
2. Main steam line radiation high
3. Main steam line flow high
4. Main steam line tunnel temperature high
5. Main steam line pressure low
6. Condenser vacuum low

GROUP 2: The valves in Group 2 are actuated by one one of the following conditions:

1. Reactor vessel water level low (Level 3)
2. Drywell pressure high

GROUP 3: Isolation valves in the high pressure coolant injection (HPCI) system are actuated by any one of the following conditions:

1. HPCI steam line flow high
2. High temperature in the vicinity of the HPCI steam line
3. HPCI steam line pressure low
4. HPCI turbine exhaust diaphragm pressure

GROUP 4: Primary Containment Isolation valves in the reactor core isolation cooling (RCIC) system are actuated by any one of the following conditions:

1. RCIC steam line flow high
2. High temperature in the vicinity of the RCIC steam line
3. RCIC steam line pressure low

GROUP 5: The valves in Group 5 are actuated by any one of the following conditions:

1. Reactor vessel water level Low Low (Level 2)
2. Reactor water cleanup equipment room temperature high
3. Reactor water cleanup equipment room ventilation differential temperature high
4. Reactor water cleanup system differential flow high
5. Actuation of Standby Liquid Control System - closes outside valve only
6. High temperature following non-regenerative heat exchanger - closes outside valve only

GROUP 6: The valves in Group 6 are actuated by the following conditions:

1. Reactor vessel water level low (Level 3)
2. Reactor vessel steam dome pressure high (shutdown cooling mode)

c. Requires a Group 2 signal or a Reactor Building ventilation high radiation isolation signal.

d. For redundant lines, only one set of valves is listed. Other sets are identical except for valve numbers, which are included. Valve numbers are listed in order from within primary containment outward for each line.

e. Not applicable to check valves.

3.7.D. Primary Containment Isolation Valves

Double isolation valves are provided on lines penetrating the primary containment and open to the free space of the containment. Closure of one of the valves in each line would be sufficient to maintain the integrity of the system. Automatic initiation is required to minimize the potential leakage paths from the containment in the event of a loss-of-coolant accident.

Table 3.7-1 contains primary containment isolation valves that automatically actuate on a primary containment isolation signal. The primary containment isolation signals are grouped as described below.

Group 1 process lines are isolated by reactor vessel water level low low low (Level 1) in order for removal of decay heat subsequent to a scram, yet isolate in time for proper operation of the core standby cooling systems.

Group 2 isolation valves are not normally in use and are closed by reactor vessel water level low (Level 3) or drywell pressure high. It is not desirable to actuate the Group 2 isolation signal by a transient or spurious signal.

Group 3 and 4 process lines are designed to remain operable and mitigate the consequences of an accident which results in the isolation of other process lines. The signals which initiate isolation of Group 3 and 4 process lines are therefore indicative of a condition which would render these other lines inoperable.

Group 5 process lines are normally in use and it is therefore not desirable to cause spurious isolation due to high drywell pressure resulting from non-safety related causes. To protect the reactor from a possible pipe break in the system, isolation is provided by high temperature in the cleanup system area or high flow difference through the cleanup system. Also since the vessel could potentially be drained through the cleanup system, a low level isolation is provided.

Group 6 isolation valves are not normally in use and are closed by reactor vessel water level low (Level 3) and reactor steam dome pressure low permissive.

The primary containment is penetrated by several small diameter instrument lines connected to the reactor coolant system. Each instrument line contains a 0.25 inch restricting orifice inside the primary containment, a manually operated root valve outside the primary containment, and an excess flow check valve outside the primary containment.

APPENDIX 1

SIGNIFICANT HAZARDS REVIEW

Overview of the Individual 10 CFR 50.92 Evaluations of the Proposed ATTS-Related Technical Specifications Changes for the Edwin I. Hatch Nuclear Plant-Unit 1

The proposed Technical Specifications changes, which Georgia Power Company (GPC) is proposing for use with the new analog transmitter trip system (ATTS) to be installed at Hatch 1, include new instrument trip setpoints/allowable values and surveillance intervals which take credit for the advantages that the new devices have over those currently installed at the plant, in terms of setpoint drift and instrument accuracy. In addition to these types of revisions, this submittal also proposes a number of other types of Technical Specifications changes including the following:

- Changes which account for modifications to instrument loops or trip logic resulting from the new ATTS design.

- Changes which correct minor typographical or descriptive errors found in the Hatch 1 Technical Specifications during the safety review process for ATTS. (The errors found do not necessarily affect sections covering requirements for ATTS components.)

- Changes to the Technical Specifications Bases sections which correct existing errors and update them with respect to the other proposed ATTS changes.

All of these proposed modifications were based on Nuclear Regulatory Commission (NRC) and industry standards listed in Table A1-1 of this appendix, to the extent practicable. It should be noted that use of several documents in Table A1-1 goes beyond the extent of commitments made by GPC, including those made in the Hatch 1 FSAR, and that their use in the design and implementation of ATTS does not represent an extension by GPC of these commitments to other plant systems designed to other criteria. If conflicts arose between the requirements of the FSAR and those contained in the listed standards, the requirements of Hatch 1 FSAR section 7.1 and Appendix F were followed by GPC.

The individual 10 CFR 50.92 evaluations contained in the following pages, when taken collectively, provide a complete evaluation for significant hazards resulting from the proposed ATTS-related license changes. Based on the conclusion of each of the individual reviews, which was that each type or group of changes did not result in a significant hazard as defined in 10 CFR 50.92, GPC has determined that the same conclusion is valid for this entire license change proposal.

TABLE A1-1

ANALOG TRANSMITTER TRIP SYSTEM CONFORMANCE CRITERIA (SHEET 1 OF 3)

IEEE Standards

IEEE-279-1971: Criteria for Protection System for Nuclear Power Generating Station

IEEE-323-1974: Qualifying Class 1E Equipment for Nuclear-Power Generating Stations

IEEE-336-1977: Installation, Inspection and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations

IEEE-338-1977: Criteria for Periodic Testing of Nuclear Power Generating Station Safety Systems

IEEE-344-1975: Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations

IEEE-397-1977: Application of the Single-Failure Criterion to Nuclear Power Generating Station Class 1E Systems

IEEE-420-1973: Trial-Use Guide for Class 1E Control Switchboards for Nuclear Power Generating Stations

IEEE-494-1974: Method for Identification of Documents Related to Class 1E Equipment and Systems for Nuclear Power Generating Stations

NRC Regulatory Guides

Regulatory Guide 1.22: Periodic Testing of Protection System Actuation Functions

Regulatory Guide 1.28: Quality Assurance Program Requirements

Regulatory Guide 1.29: Seismic Design Classification

Regulatory Guide 1.30: Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment

Regulatory Guide 1.38: Quality Assurance Requirements for Packing, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants

Regulatory Guide 1.47: Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

NRC Regulatory Guides (continued)

Regulatory Guide 1.53: Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems

Regulatory Guide 1.61: Damping Value for Seismic Design of Nuclear Power Plants

Regulatory Guide 1.62: Manual Initiation of Protective Actions

Regulatory Guide 1.64: Quality Assurance Requirements for the Design of Nuclear Power Plants

Regulatory Guide 1.68: Initial Test Program for Water-Cooled Reactor Power Plants

Regulatory Guide 1.75: Physical Independence of Electrical Systems

Regulatory Guide 1.89: Qualification of Class 1E Equipment for Nuclear Power Plants

Regulatory Guide 1.92: Combining Modal Responses and Spatial Components in Seismic Response Analysis

Regulatory Guide 1.97: Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident

Regulatory Guide 1.100: Seismic Qualification of Electric Equipment for Nuclear Power Plants

Regulatory Guide 1.131: Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants

NRC Regulations

Regulation 10 CFR 21: Reporting of Defects and Noncompliance

Regulation 10 CFR 50.49: Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Regulation 10 CFR 50.55a: Issuance, Limitation and Conditions of Licenses and Construction Permits (CP) - Codes and Standards

Regulation 10 CFR 50, Appendix A: General Design Criteria (GDC) for Nuclear Power Plants

TABLE A1-1 (SHEET 3 OF 3)

General Design Criteria

GDC 1: Quality Standards and Records

GDC 2: Design Basis for Protection Against Natural Phenomena

GDC 5: Sharing of Structures, Systems, and Components

GDC 10: Reactor Design

GDC 13: Instrumentation and Control

GDC 20: Protection System Functions

GDC 21: Protection System Reliability and Testability

GDC 22: Protection System Independence

GDC 23: Protection System Failure Mode

GDC 24: Separation of Protection and Control Systems

GDC 29: Protection Against Anticipated Operational Occurrences

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications Surveillance Intervals as a Result of the Installation of the Analog Transmitter Trip System for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed Technical Specification changes due to the installation of the analog transmitter trip system (ATTS). ATTS replaces the pressure, level, and temperature switches in the reactor protection system and the emergency core cooling system (ECCS) with analog sensor/trip unit combinations. The system is designed to improve sensor intelligence and reliability, while still providing continued monitoring of critical parameters and performing the intended basic logic function. Since the ATTS instrumentation is superior in design to the mechanical switches currently used at Plant Hatch, certain surveillance intervals may be extended without any significant effect on the expected magnitude of sensor drift or frequency of instrument malfunction. GPC proposes to change the surveillance requirements for the ATTS instrumentation to once per shift for channel checks, once per month for channel functional tests, and once per operating cycle for channel calibrations. These proposed surveillance requirements were previously approved on a generic bases for ATTS equipment by the Nuclear Regulatory Commission (NRC) review of the General Electric Company topical report NEDO 21617-A. Additional changes to the nomenclature used in the Technical Specifications are included for clarification and consistency with this proposed change.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They would not significantly increase the probability or consequences of an accident previously evaluated, because the new ATTS instruments have been demonstrated to be superior in design to the existing devices in terms of instrument accuracy and drift characteristics. In addition, the new setpoints have been rigorously calculated, assuming the proposed surveillance frequencies.

2. They would not create the possibility of a new or different accident from any accident previously evaluated, because the new surveillance intervals for ATTS were developed to be consistent with the Plant Hatch-Unit 1 Final Safety Analysis Report (FSAR) descriptions.

3. They would not involve a significant reduction in a margin of safety, because the new surveillance requirements are tailored to the ATTS instruments, using the methodology of Regulatory Guide 1.105. In addition, the bases for the margins of safety, as described in the FSAR, have been maintained.

a. See section 3B (page 3-40) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications as a Result of the Incorporation of the Low Low Set Relief Design Modification for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed addition of the low low set (LLS) relief logic technical specifications. The purpose of the LLS design modification is to mitigate the induced loads of subsequent safety/relief valve (S/RV) actuations as identified in NUREG-0661. The load reduction is accomplished by lowering the opening and closing setpoints of four non-automatic depressurization system (ADS) S/RVs after initial S/RV opening. Technical Specifications revisions are required to accurately reflect the newly designated safety function of the selected S/RVs. The proposed limiting conditions of operation requirements were developed taking into consideration the General Electric BWR/4 Standard Technical Specifications, while the surveillance requirements were developed from the ATTS requirements. This modification is required by the Nuclear Regulatory Commission (NRC) order requiring that reassessment of the containment design for suppression pool hydrodynamic loading conditions be promptly instituted and that any plant modifications needed to conform to the NRC staff's acceptance criteria, contained in Appendix A to NUREG-0661, be performed.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They would not significantly increase the probability or consequences of an accident or equipment failure previously evaluated, because this new system was designed to reduce the consequences of certain plant transients without any significant effect on other accident scenarios.

2. They would not create the possibility of a new or different accident from any accident previously evaluated, because the potential accident scenarios following implementation of these changes are bounded by those in the FSAR analysis.

3. They would not involve a significant reduction in a margin of safety, because the bases for the proposed operability limits and surveillance requirements for this new system are consistent with the bases for current Technical Specifications requirements.

a. See subsection 4B.1 (page 4-4) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications due to the Lowering of the Main Steam Isolation Valve Water Level for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed Technical Specifications revisions due to the lowering of the main steam isolation valve (MSIV) water level trip setpoint. The proposed modification lowers the isolation level of the MSIVs, the main steam drain isolation valve, and the reactor water sample line isolation valves from reactor vessel water level 2 to level 1. The purpose of lowering the MSIV water level trip setpoint, as detailed in NEDE-22223 and NEDE-22224, is to provide an additional means to mitigate the induced loads of subsequent safety/relief valve (S/RV) actuations. Lowering the setpoint delays the MSIV closure allowing more steam to be released from the reactor prior to an S/RV actuation. Subsequently, the pressurization rate after isolation is reduced, and the time period between S/RV actuations is increased. This change also reduces the probability of spurious MSIV trips and scrams, prevent unnecessary use of the suppression pool as the alternate heat sink, and improve the life expectancy of the feedwater sparger. This modification is required by the Nuclear Regulatory Commission (NRC) order requiring that reassessment of the containment design for suppression pool hydrodynamic loading conditions be promptly instituted that and any plant modifications needed to conform to the NRC staff's acceptance criteria, contained in Appendix A to NUREG-0661, be performed.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They would not significantly increase the probability or consequences of an accident or equipment failure previously evaluated, because this new system was designed to reduce the consequences of certain plant transients without any significant effect on other accident scenarios.

2. They would not create the possibility of a new or different accident from any accident previously evaluated, because the potential accident scenarios following implementation of these changes are bounded by those in the FSAR analysis.

3. They would not involve a significant reduction in a margin of safety, because the bases for the proposed operability limits and surveillance requirements for this new system are consistent with the bases for current Technical Specifications requirements.

a. See subsection 4B.2 (page 4-16) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications Reactor Vessel Water Level - Low Low (Level 2) Trip Setpoint for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed reactor vessel water level 2 trip setpoint Technical Specifications change. This proposed change lowers the level 2 trip setpoint/allowable value from -38 in. to -55 in., thus, potentially decreasing the number of plant transients by decreasing the number of HPCI/RCIC actuations due to normal operational perturbations in water level.

GPC reviewed the proposed change and considers it not to involve a significant hazards consideration for the following reasons:

1. It will not significantly increase the probability or consequences of an accident previously evaluated, because a reevaluation of the FSAR analysis showed that the new setpoint, in conjunction with the new analog transmitter trip system (ATTS) instrumentation, would still provide the same degree of plant protection as described in the Final Safety Analysis Report (FSAR).

2. It will not create the possibility of a new or different accident from any accident previously evaluated, because the lowered setpoint is still within the bounds of the plant safety analysis and should decrease the number of unnecessary emergency core cooling system actuations.

3. It will not involve a significant reduction in a margin of safety, because the setpoint still performs its intended safety function, as described in the FSAR. In addition, the calculations which determined the new setpoint took credit for the improved drift characteristics of the ATTS instruments and the criteria of Regulatory Guide 1.105.

a. See subsection 4B.3 (page 4-17) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications due to the Reactor Vessel Water Level - High (Level 8) Trip Instrumentation Modification for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed changes to the Technical Specifications due to the reactor vessel water level - high (level 8) trip instrumentation. This change proposes to replace the current instruments with new ATTS units. Since the ATTS instruments are superior in design to the mechanical switches currently used at Plant Hatch, using the criteria of Regulatory Guide 1.105, the setpoint/allowable value will be lowered from 58 in. to 56.5 in.

GPC reviewed the proposed change and considers it not to involve a significant hazards consideration, because it represents a more conservative and restrictive Technical Specifications requirement than that which is currently in place. Consequently, this change is consistent with Item (ii) of the "Examples of Amendments that are Considered Not Likely to Involve Significant Hazards Considerations" listed on page 14,870 of the April 6, 1983, issue of the Federal Register and will not result in a significant hazards consideration.

a. See subsection 4B.4 (page 4-18) for discussion of proposed revisions.

10 CFR 50.92 Evaluation of the Proposed Change to the Technical Specifications Reactor Core Isolation Cooling Reactor Vessel Water Level 8 Trip for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed change to the reactor core isolation cooling (RCIC) reactor vessel water level 8 Technical Specifications. This change proposes to clarify the Technical Specifications by adding a note to table 3.2-3 and the Bases stating that the RCIC system is capable of automatic reset after a level 8 trip. Since there is no physical change to the RCIC system level 8 trip, GPC considers this change to be purely administrative in nature.

As discussed above, the proposed change is submitted in an effort to update informational sections of the Technical Specifications and is administrative in nature. Therefore, GPC has determined that the proposed change is consistent with Item (i) of the "Examples of Amendments that are Considered Not Likely to Involve Significant Hazards Considerations" listed on page 14,870 of the April 6, 1983, Federal Register and will not involve a significant hazards consideration.

a. See subsection 4B.5 (page 4-19) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications due to the Lowered Water Level Trip Setpoint for Isolation of Reactor Water Cleanup and Secondary Containment, and Starting of Standby Gas Treatment System for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed changes to the Technical Specifications due to the lowered water level trip setpoint for the isolation of reactor water cleanup (RWCU) and secondary containment, and the starting of the standby gas treatment system (SGTS). This change proposes to lower the water level trip setpoint for the isolation of RWCU and secondary containment and startup of SGTS from level 3 to level 2. A reactor scram from normal power (<50-percent rated) usually results in a reactor vessel water level transient due to a void collapse that causes RWCU isolation at level 3. This usually results in the dropping of the cleanup filter cake, and added radwaste processing. These problems can be avoided by lowering RWCU isolation to level 2. Lowering the SGTS actuation and secondary containment isolation from level 3 to level 2 reduces the probability of spurious isolations.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They will not significantly increase the probability or consequences of an accident from any accident previously evaluated, because the Final Safety Analysis Report (FSAR) emergency core cooling system analysis system already assumes SGTS initiation at level 2. Secondary containment requires a functioning train of the SGTS for full effectiveness, and isolation of the containment building is assumed to be simultaneous with SGTS initiation in the FSAR analysis. In addition, the changes will reduce operability problems associated with unnecessary RWCU and secondary containment isolations.

2. They will not create the possibility of a new or different kind of accident from any accident previously evaluated, because the lowered setpoint is still within the bounds of the FSAR analysis and will not change the basic functions of these trips.

3. They will not involve a significant reduction in a margin of safety, because these trips still perform their intended safety functions, as described in the FSAR.

a. See subsection 4B.6 (page 4-20) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications due to the Deletion of the High Drywell Pressure Signal for Residual Heat Removal (Shutdown Cooling Mode) and RPV Head Spray Valve for Edwin I. Hatch Nuclear Plant-Unit 1 [a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed changes to the Technical Specifications due to the deletion of the high drywell pressure signal for residual heat removal (RHR) (shutdown cooling mode) and the reactor pressure vessel head spray valve. The purpose of this change is to stop small steam leaks in the drywell from preventing operation of the RHR system during the shutdown cooling mode, thereby prohibiting an acceptable normal shutdown procedure.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They will not significantly increase the probability or consequences of an accident previously evaluated; because the requirements of 10 CFR 100 are still met, and the Appendix K calculations are not affected.

2. They will not create the possibility of a new or different kind of accident from any accident previously evaluated, because the deletion of the drywell pressure isolation is only being made on closed-loop systems. In addition, General Electric has shown that the reactor vessel low water level trip function, which isolates the shutdown cooling mode of RHR, is adequate for reactor protection. Furthermore, this change does eliminate the possibility for isolation of the shutdown cooling system due to high drywell pressure during periods when its function is essential for adequate decay heat removal.

3. They will not involve a significant reduction in a margin of safety, because the high drywell pressure isolation has little effect in preventing coolant losses or radioactive substance releases, and presently hinders the operability of the RHR shutdown cooling systems during certain plant scenarios.

a. See subsection 4B.7 (page 4-21) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Change to the Safety/Relief Valve Position Indicator Technical Specifications for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed safety/relief valve (S/RV) position indicator Technical Specifications. This change proposes to correct the S/RV primary position indicator range from 0-400 psig to 85 psig, because the new qualified S/RV pressure switches do not have a variable-range indication capability. However, the setpoint would not change since it is presently 85 psig. Since an indicating light at the setpoint is turned on and off by pressure switches, the Technical Specifications would also be revised to reflect the S/RV primary position indicator as an indicating light. This change also proposes to correct the S/RV secondary position indicator type from a temperature element to a recorder, since the recorder is the instrument that actually provides surveillance. GPC considers these changes to be administrative in nature because no plant modifications are required.

As discussed above, these proposed changes clarify and correct the Technical Specifications. GPC determined that the proposed changes are administrative in nature and are consistent with Item (i) of the "Examples of Amendments that are Considered Not Likely to Involve Significant Hazards Considerations" listed on page 14,870 of the April 6, 1983, issue of the Federal Register. Thus, the proposed changes will not involve a significant hazards consideration.

a. See subsection 4B.8 (page 4-22) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Change to the Residual Heat Removal (RHR) Shutdown Cooling Mode Safety Limit Technical Specifications for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed residual heat removal (RHR) shutdown cooling mode safety limit Technical Specifications change. The purpose of this change is to clarify and correct the HNP-1 Technical Specifications. The Technical Specifications currently list a safety limit of 135 psig for the reactor vessel steam dome pressure. This value is also listed as a trip setpoint. The actual safety limit is and has always been 162 psig. In addition, the bases for the safety limit and the limiting safety system settings are reversed. Therefore, this change proposes to revise the safety limit from 135 psig to 162 psig and switch the bases for the safety limit and the limiting safety system settings. Since this change only corrects an error, GPC considers this change to be purely administrative in nature.

As discussed above, this proposed change clarifies and corrects the Technical Specifications. GPC determined that the proposed change is administrative in nature and is consistent with Item (i) of the "Examples of Amendments that are Considered Not Likely to Involve Significant Hazards Considerations" listed on page 14,870 of the April 6, 1983, of the Federal Register. Thus, the proposed change will not involve a significant hazards consideration.

a. See subsection 4B.9 (page 4-23) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Elimination of the MSIV Closure Scram in the Startup/Hot Standby Mode for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed Technical Specifications revision due to the elimination of the main steam isolation valve (MSIV) closure scram in the startup/hot standby mode. This change proposes to disable the reactor scram on MSIV closure with the vessel pressure exceeding the scram pressure in the startup/hot standby mode. Since normal operating pressures in the startup/hot standby mode are significantly less than 1045 psig (scram pressure), and since the reactor will scram on high pressure should the reactor steam dome pressure exceed 1045 psig regardless of MSIV position, this scram is essentially bypassed. Therefore, this change will not affect plant safety.

GPC reviewed the proposed change and considers it not to involve a significant hazards consideration for the following reasons:

1. It will not significantly increase the probability or consequences of an accident previously evaluated, because the trip is already essentially bypassed and provides no safety function.

2. It will not create the possibility of a new or different kind of accident from any accident previously evaluated, because this trip is already essentially bypassed and provides no safety function.

3. It will not involve a significant reduction in a margin of safety, because this trip is already essentially bypassed and provides no safety function.

a. See subsection 4B.10 (page 4-24) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Trip Function Identification Changes to the Technical Specifications for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed trip function identification changes to the Technical Specifications. Since the proposed changes only involve revisions in nomenclature, GPC considers them to be purely administrative in nature.

As discussed above, the proposed changes only involve changes in nomenclature. Therefore, GPC determined that these proposed changes are consistent with Item (i) of the "Examples of Amendments that are Considered Not Likely to Involve Significant Hazards Considerations" listed on page 14,870 of the April 6, 1983, issue of the Federal Register and will not involve a significant hazards consideration.

a. See subsection 4B.9 (page 4-25) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Miscellaneous Trip Setpoint/Allowable Value Modifications to the Technical Specifications for Edwin I. Hatch Nuclear Plant-Unit 1[a]

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed miscellaneous trip setpoint/allowable value modifications to the Technical Specifications. The purpose of this change is to update the Technical Specifications trip setpoints being replaced by the analog transmitter trip system (ATTS). Since the time that original setpoints were determined, a better calculational method has been developed. This proposed change uses the Regulatory Guide 1.105 methodology in updating the setpoints for the instruments being replaced with the ATTS units, and takes credit for the improved error and drift characteristics of the new system. This change replaces the trip setpoints listed in the Technical Specifications which are the original analytical limits with the newly evaluated allowable values determined through Regulatory Guide 1.105 methodology.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They will not significantly increase the probability or consequences of an accident previously evaluated, because the new ATTS instruments are of a superior design as compared to the current instruments. In addition, the setpoints were determined using the criteria of Regulatory Guide 1.105, and therefore, still meet the Final Safety Analysis Report (FSAR) criteria.

2. They will not create the possibility of a new or different kind of accident from any accident previously evaluated, because the basic trip functions, as described in the FSAR, are unchanged.

3. They will not involve a significant reduction in a margin of safety, because for most trips, the original design basis was maintained. Any new design bases were fully addressed with regard to FSAR requirements. In addition, Regulatory Guide 1.105 criteria were used in the calculation of the new setpoints.

a. See subsection 4B.10 (page 4-26) for discussion of proposed revisions.