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10CFR50.55a

2130-03-20190
June 23, 2003

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Response to Request for Additional Information Concerning the Fourth Ten-Year Interval Inservice Inspection Program

References: 1) Letter from M. P. Gallagher (AmerGen Energy Company, LLC) to U. S. Nuclear Regulatory Commission, dated August 1, 2002

2) Letter from P. S. Tam (U. S. Nuclear Regulatory Commission) to J. L. Skolds (AmerGen Energy Company, LLC), dated April 17, 2003

Dear Sir/Madam:

In the Reference 1 letter, AmerGen Energy Company, LLC submitted for your review and approval proposed alternatives and a relief request in accordance with 10CFR50.55a, associated with the Fourth Ten-Year Interval Inservice Inspection (ISI) Program for Oyster Creek Generating Station (OCGS). Reference 2 requested additional information regarding these proposed alternatives and relief request. Attached is our response.

If you have any questions or require additional information, please do not hesitate to contact us.

Very truly yours,

Michael P. Gallagher

Michael P. Gallagher
Director, Licensing & Regulatory Affairs
AmerGen Energy Company, LLC

Attachment - Oyster Creek Generating Station Response to Request for Additional Information

cc: H. J. Miller, Administrator, USNRC, Region I (w/attachment)
S. Dennis, Acting USNRC Senior Resident Inspector, OCGS (w/attachment)
P. Tam, Senior Project Manager, USNRC (w/attachment)
File No. 02064

A047

bcc: G. C. Pardee - KSA 3-N
J. A. Benjamin - Cantera
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Correspondence Control Desk - KSA 1-N-1
DAC, KSA 1-N-1
R. Francis - OCGS
G. Harttraft – OCGS
F. Buckley - OCGS

ATTACHMENT

OYSTER CREEK GENERATING STATION

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

Question 1 (OC-02-01):

The licensee has not provided sufficient evidence to support a determination that IGSCC, generated from the inside surface of these piping welds, is the only service-induced degradation that may be manifested in all B-J and C-F-1 piping during the operating life of the plant. The Staff has determined that operating history alone does not provide adequate justification to eliminate Code-required examinations because operational experience also has demonstrated that components degrade as they age. A thorough degradation mechanism analysis would be necessary to support the alternative, to target only IGSCC, as proposed by the licensee.

A precedent for this type of analysis has been set within the risk-informed inservice inspection (RI-ISI) initiatives which have recently been approved by the Staff. During the RI-ISI process, detailed degradation mechanism assessments are required to support the failure frequency side of the risk matrix. As a result of these analyses, nondestructive examination (NDE) methods, and inspection frequencies, if necessary, are chosen to target specific areas for potential degradation. In doing so, many licensee's have been able to show that OD-generated flaws would not be expected to occur at certain piping locations, thus only volumetric examinations are implemented. In order to establish this basis at Oyster Creek, a similar degradation mechanism assessment would be required. Provide a detailed degradation mechanism assessment, as outlined in the EPRI, or Westinghouse Owners Group (WOG), topical reports for performing risk-informed ISI.

Response:

A detailed Damage Mechanism Assessment report has been completed for Class 1 and 2 Piping Systems at Oyster Creek Generating Station. This report identifies that the only damage mechanism that could effect the outside surface of the Class 1 and 2 piping is External Chloride Stress Corrosion Cracking (ECSCC). The report concludes that the Class 1 and 2 piping at Oyster Creek Generating Station is not considered susceptible to ECSCC as discussed in the report. Attachment A provides the report.

Question 2 (OC-02-02):

A typical configuration as shown in Figure IWB-2500-13 has been presented. However, the licensee has not provided sufficient detail to demonstrate the impracticality of the surface examinations, due to these specific interferences at Oyster Creek. Please provide, through drawings or sketches, photographs, or more detailed technical descriptions, further information to support a determination of impracticality. Include in this information the variables that produce the surface examination limitations with respect to magnetic particle or liquid penetrant testing.

The licensee argued that their nondestructive examination group pursued the use of an alternative ultrasonic method in lieu of the required surface examinations on the inside surface area C-D of Weld 1-569. The licensee concluded that, due to the unique configuration of the Oyster Creek RPV skirt design, an ultrasonic examination would not provide Code examination coverage. However, no physical description or other component specific information has been provided to support this conclusion. The Staff notes that other licensee's with typical RPV skirt weld configurations have applied ultrasonic methods to examine all or large percentages of the Code-required surface areas. Please provide sufficient information to enable the Staff to determine whether ultrasonic techniques may be applied at Oyster Creek.

The licensee stated, as part of their alternative examination, that Oyster Creek will "perform a VT-3 visual examination of the support skirt IWB boundary as shown in Figure IWB-2500-13 for any support deformation." It is unclear whether the VT-3 visual will be conducted as a direct, or remote, inspection, and whether the IWB boundary is intended to include the surface areas A-B and C-D, as described in Figure IW B-2500-13. It is also unclear what is meant by the phrase "any support deformation." Please clarify.

Response:

The support skirt does not contain personnel access holes or inspection ports that would allow examination of the C-D surface area to the extent required by the Code. Attached Diagram A provides a view of the Oyster Creek vessel and the location of the vessel skirt. As discussed in our relief request, control rod drive housings and incore housings restrict access for examination of area C-D. Diagram B shows the location of the skirt, and as shown on Diagram B, no access points are provided for examining area C-D. Diagram C provides a closer view of the skirt and refers to Detail "E" which is shown in Diagram D. As discussed in the relief request, an ultrasonic examination was considered as an alternative, but as shown on Diagram D, the 1 1/2 inch radius demonstrates the limited capability to perform this type of exam. As discussed in the relief request, as an alternative to the code requirements, AmerGen proposed to perform a surface examination of area A-B, and perform a VT-3 visual examination of the IWB boundary as shown in Figure IWB-2500-13 of the relief request. This examination would inspect for support member degradation, which includes surface indications or defects.

Question 3 (OC-02-04):

Item 1) of the licensee's alternative is not entirely consistent with the Staff's position regarding visual examinations of containment bolted connections. The licensee is supplanting the requirements in Category E-G with those of Category E-A. This is essentially the same approach as found in later revisions of the Code (1997 Addenda, 1998 Edition, 1999 and 2000 Addenda). The Staff has reviewed this change and determined that a general visual examination using VT-3 personnel qualified in accordance with IWA-2300 may be acceptable, with certain provisions, as listed in the Final Rule, Section 10 CFR 50.55a(b)(ix)(H):

(E) A general visual examination as required by Subsection IW E must be performed once each period.

(F) VT-1 and VT-3 examinations must be conducted in accordance with IWA-2200. Personnel conducting examinations in accordance with the VT-1 or VT-3 examination method shall be qualified in accordance with IWA-2300. The "owner-defined" personnel qualification provisions in IW E-2330(a) for personnel that conduct VT-1 and VT-3 *examinations are not approved for use.*

(G) The VT-3 examination method must be used to conduct the examinations in Items E1.12 and E1.20 of Table IW E-2500-1, and the VT-1 examination method must be used to conduct the examination in Item E4.11 of Table IWE2500-1. An examination of the pressure-retaining bolted connections in Item E1.11 of Table IWE-2500-1 using the VT-3 examination method must be conducted once each interval. The "owner-defined" visual examination provisions in IW E-2310(a) are not approved for use for VT-1 and VT-3 examinations.

(H) Containment bolted connections that are disassembled during the scheduled performance of the examinations in Item E1 .11 of Table IWE-2500-1 must be examined using the VT-3 examination method. Flaws or degradation identified during the performance of a VT-3 examination must be examined in accordance with the VT-1 examination method. The criteria in the material specification or IW B-3517.1 must be used to evaluate containment bolting flaws or degradation. As an alternative to performing VT-3 examinations of containment bolted connections that are disassembled during the scheduled performance of Item E1.11, VT-3 examinations of containment bolted connections may be conducted whenever containment bolted connections are disassembled for any reason.

(I) The ultrasonic examination acceptance standard specified in IW E-3511.3 for Class MC pressure-retaining components must also be applied to metallic liners of Class CC pressure-retaining components.

The licensee must confirm the provisions stated above will be met as part of the proposed alternative in Request for Relief OC-02-04.

<u>Response</u>:

Upon further review, this relief request (OC-02-04) is being withdrawn.

ATTACHMENT A

Damage Mechanism Assessment for Class 1 and 2 Piping Systems at Oyster Creek

Report No. SIR-03-078
Revision No. 0
June 2003

Report No.: SIR-03-078
Revision No.: 0
Project No.: OC-04Q
File No.: OC-04Q-401
June 2003

Damage Mechanism Assessment for
Class 1 and 2 Piping Systems
at Oyster Creek

Prepared for:

AmerGen Energy

Prepared by:

Structural Integrity Associates, Inc.
San Jose, California

Prepared by: Miroslav Trubelja Date: 6/16/03

Reviewed by: for Scott T. Chesworth Date: 6/16/03

Approved by: Nathaniel G. Cofie Date: 6/16/03

REVISION CONTROL SHEET

Document Number: SIR-03-078

Title: Damage Mechanism Assessment for Class 1 and 2 Piping Systems at Oyster Creek

Client: AmerGen Energy

SI Project Number: OC-04Q

Section	Pages	Revision	Date	Comments
1	1-1 – 1-2	0	06/10/03	Initial Issue
2	2-1 – 2-4			
3	3-1 – 3-4			
4	4-1			
5	5-1			
6	6-1			
App. A	A-1 – A-2			

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List of Tables

1.0 INTRODUCTION

1.1 Background and Technical Approach

The purpose of this calculation is to perform a degradation mechanism evaluation on selected Class 1 and Class 2 piping, in support of eliminating the surface exams on Category B-F, B-J, C-F-1 and C-F-2 welds at Oyster Creek. This degradation mechanism evaluation is performed in accordance with the industry standard process specified in EPRI TR-112657 [1]

The degradation mechanisms that affect nuclear power plant piping are identified in EPRI TR-112657. These mechanisms include:

- Thermal Fatigue
  - Thermal Stratification, Cycling, Striping (TASCS)
  - Thermal Transient (TT)
- Stress Corrosion Cracking
  - Intergranular Stress Corrosion Cracking (IGSCC)
  - Transgranular Stress Corrosion Cracking (TGSCC)
  - External Chloride Stress Corrosion Cracking (ECSCC)
  - Primary Water Stress Corrosion Cracking (PWSCC)
- Localized Corrosion
  - Microbiologically-Influenced Corrosion (MIC)
  - Pitting (PIT)
  - Crevice Corrosion (CC)
- Flow Sensitive Corrosion
  - Erosion-Cavitation (E-C)
  - Flow-Accelerated Corrosion (FAC)

The criteria to establish the potential for each degradation mechanism are described in detail in Section 2 of this calculation.

Of the listed mechanisms, all except ECSCC primarily affect the inside (ID) surface of a pipe because of the operating environment. Since the purpose of this evaluation is to provide justification for elimination of external surface examinations, the evaluation given in Section 3 will concentrate on showing that ECSCC is not an active degradation mechanism in the in-scope piping.

It should also be mentioned that the approach outlined here is also consistent with that documented in ASME Code Case N-633 [2] which provides alternate requirements for Class 1 and Class 2 surface examinations.

1.2 Scope

The following Oyster Creek systems contain all in-scope piping welds:

System	System Number
Isolation Condenser	211
Core Spray	212
Shutdown Cooling	214
Cleanup Demineralization	215
Reactor Recirculation	223
Main Steam	411
Feedwater	422

The potential for ECSCC in these systems are evaluated in Section 3.

1.3 Assumptions

All lines evaluated in this calculation were assumed to operate under some degree of tensile stress (note: this is a conservative assumption when applying the EPRI criteria).

2.0 DEGRADATION MECHANISMS

The degradation mechanisms to be assessed are given below:

TASCS	Thermal Stratification, Cycling, Striping
TT	Thermal Transient
IGSCC	Intergranular Stress Corrosion Cracking
TGSCC	Transgranular Stress Corrosion Cracking
ECSCC	External Chloride Stress Corrosion Cracking
PWSCC	Primary Water Stress Corrosion Cracking
MIC	Microbiologically Influenced Corrosion
PIT	Pitting
CC	Crevice Corrosion
E-C	Erosion-Cavitation
FAC	Flow-Accelerated Corrosion

TASCS and TT are grouped under the general heading Thermal Fatigue (TF). IGSCC, TGSCC, ECSCC and PWSCC are grouped under Stress Corrosion Cracking (SCC). MIC, PIT and CC are grouped under Localized Corrosion (LC). E-C and FAC are grouped under Flow Sensitive (FS).

Specific guidance for determining potential degradation mechanisms based on the EPRI methodology [1] is provided in Table 2-1. A review of the EPRI criteria shows that the only degradation mechanism applicable to the external (OD) surface of the piping is ECSCC. This evaluation will therefore focus on establishing the potential for ECSCC in the in-scope systems.

Table 2-1

Degradation Mechanism Criteria and Susceptible Regions [1]

Degradation Mechanism		Criteria	Susceptible Regions
TF	TASCS	– NPS > 1 inch, and – pipe segment has a slope < 45° from horizontal (includes elbow or tee into a vertical pipe), and – potential exists for low flow in a pipe section connected to a component allowing mixing of hot and cold fluids, or – potential exists for leakage flow past a valve (i.e., in-leakage, out-leakage, cross-leakage) allowing mixing of hot and cold fluids, or – potential exists for convection heating in dead-ended pipe sections connected to a source of hot fluid, or – potential exists for two phase (steam/water) flow, or – potential exists for turbulent penetration into a relatively colder branch pipe connected to header piping containing hot fluid with turbulent flow, and – calculated or measured $\Delta T > 50°F$, and – Richardson number > 4.0	Nozzles, branch pipe connections, safe ends, welds, heat affected zones (HAZs), base metal, and regions of stress concentration
	TT	– operating temperature > 270°F for stainless steel, or – operating temperature > 220°F for carbon steel, and – potential for relatively rapid temperature changes including – cold fluid injection into hot pipe segment, or – hot fluid injection into cold pipe segment, and – $\lvert \Delta T \rvert > 200°F$ for stainless steel, or – $\lvert \Delta T \rvert > 150°F$ for carbon steel, or – $\lvert \Delta T \rvert > \Delta T$ allowable (applicable to both stainless and carbon)	

Table 2-1 (continued)

Degradation Mechanism		Criteria	Susceptible Regions
SCC	IGSCC (PWR)	– austenitic stainless steel (carbon content ≥ 0.035%), and – operating temperature > 200°F, and – tensile stress (including residual stress) is present, and – oxygen or oxidizing species are present <u>OR</u> – operating temperature < 200°F, the attributes above apply, and – initiating contaminants (e.g., thiosulfate, fluoride or chloride) are also required to be present	Welds and HAZs
	TGSCC	– austenitic stainless steel, and – operating temperature > 150°F, and – tensile stress (including residual stress) is present, and – halides (e.g., fluoride or chloride) are present, and – oxygen or oxidizing species are present	Base metal, welds, and HAZs
	ECSCC	– austenitic stainless steel, and – operating temperature > 150°F, and – tensile stress is present, and – an outside piping surface is within five diameters of a probable leak path (e.g., valve stems) and is covered with non-metallic insulation that is not in compliance with Reg. Guide 1.36, <u>OR</u> – austenitic stainless steel, and – tensile stress is present, and – an outside piping surface is exposed to wetting from concentrated chloride-bearing environments (i.e., sea water, brackish water, or brine)	Base metal, welds, and HAZs

Table 2-1. (continued)

Degradation Mechanism		Criteria	Susceptible Regions
SCC (cont)	PWSCC	– piping material is Inconel (Alloy 600), and – exposed to primary water at T > 570°F, and – the material is mill-annealed and cold worked, <u>OR</u> – cold worked and welded without stress relief	Nozzles, welds, and HAZs without stress *relief*
LC	MIC	– operating temperature < 150°F, and – low or intermittent flow, and – pH < 10, and – presence/intrusion of organic material (e.g., Raw Water System), or – water source is not treated with biocides, or	Fittings, welds, HAZs, base metal, dissimilar metal joints (for example, welds and *flanges*), and regions containing crevices
	PIT	– potential exists for low flow, and – oxygen or oxidizing species are present, and – initiating contaminants (e.g., fluoride or chloride) are present	
	CC	– crevice condition exists (i.e., thermal sleeves), and – operating temperature > 150°F, and – oxygen or oxidizing species are present	
FS	E-C	– cavitation source, and – operating temperature < 250°F, and – flow present > 100 hrs./yr., and – velocity > 30 ft./sec., and – $(P_d - P_v) / \Delta P < 5$	*Fittings, welds, HAZs,* and base metal
	FAC	– evaluated in accordance with existing plant FAC program	per plant FAC program

3.0 ECSCC EVALUATION

3.1 Materials and Conditions

Table 3-1 from Reference [3] lists piping size, system ID, class, materials, normal operating conditions and insulation information for all of the Oyster Creek in-scope piping. The "Appendix A Table" column references the table in Appendix A where the line was evaluated.

3.2 ECSCC Evaluation

Checklists applying the ECSCC criteria of the EPRI procedure (Table 2-1) to the in-scope piping runs are given in Appendix A. A summary of the evaluation for each system is given below. The information on which all evaluations are based is obtained from References [3, 4, 5 and 6], unless noted otherwise.

3.2.1 Isolation Condenser System

All Isolation Condenser piping is made of stainless steel. The operating temperature is 548°F. The piping is conservatively assumed to be under tensile stress. All piping is insulated with NUKON non-metallic insulation determined by chemical analysis to be in compliance with NRC Regulatory Guide 1.36. It is assumed, based on the plant service history evaluation, that no outside piping surfaces are exposed to wetting from concentrated chloride bearing environments. Therefore, based on the EPRI ECSCC criteria shown in Table A-1 of Appendix A, it is concluded that Isolation Condenser piping is not considered susceptible to ECSCC.

3.2.2 Core Spray System

The Class 1 Core Spray piping is made of stainless steel and the Class 2 piping is made of carbon steel. The operating temperature is 350°F. The piping is conservatively assumed to be under tensile stress. All piping is insulated with NUKON non-metallic insulation determined by chemical analysis to be in compliance with NRC Regulatory Guide 1.36. It is assumed, based on the plant service history evaluation, that no outside piping surfaces are exposed to wetting from concentrated chloride bearing environments. Therefore, based on the EPRI ECSCC criteria shown in Table A-2 of Appendix A, it is concluded that Core Spray piping is not considered susceptible to ECSCC.

3.2.3 Shutdown Cooling System

Parts of the Class 1 Shutdown Cooling piping are made of stainless steel, while the rest of the Class 1 piping, as well as all of the Class 2 piping, is made of carbon steel. The operating temperature is 350°F. The piping is conservatively assumed to be under tensile stress. All piping is insulated with NUKON non-metallic insulation determined by chemical analysis to be in compliance with NRC Regulatory Guide 1.36. It is assumed, based on the plant service history evaluation, that no outside piping surfaces are exposed to wetting from concentrated chloride bearing environments. Therefore, based on the EPRI ECSCC criteria shown in Table A-3 of Appendix A, it is concluded that Shutdown Cooling piping is not considered susceptible to ECSCC.

3.2.4 Cleanup Demineralization System

The Class 1 Cleanup Demineralization piping is made of stainless steel and the Class 2 piping is made of carbon steel. The operating temperature for Class 1 piping is 548°F and for Class 2 is 250°F. The piping is conservatively assumed to be under tensile stress. Class 1 piping is insulated with NUKON non-metallic insulation determined by chemical analysis to be in compliance with NRC Regulatory Guide 1.36. Class 2 piping is not insulated. It is assumed, based on the plant service history evaluation, that no outside piping surfaces are exposed to wetting from concentrated chloride bearing environments. Therefore, based on the EPRI ECSCC criteria shown in Table A-4 of Appendix A, it is concluded that Cleanup Demineralization piping is not considered susceptible to ECSCC.

3.2.5 Reactor Recirculation System

All Reactor Recirculation piping is made of stainless steel. The operating temperature is 528°F. The piping is conservatively assumed to be under tensile stress. All piping is insulated with

NUKON non-metallic insulation determined by chemical analysis to be in compliance with NRC Regulatory Guide 1.36. It is assumed, based on the plant service history evaluation, that no outside piping surfaces are exposed to wetting from concentrated chloride bearing environments. Therefore, based on the EPRI ECSCC criteria shown in Table A-5 of Appendix A, it is concluded that Reactor Recirculation piping is not considered susceptible to ECSCC.

3.2.6 Main Steam System

All Main Steam piping is made of carbon steel. The operating temperature for Class 1 piping is 540°F and for Class 2 is 400°F. The piping is conservatively assumed to be under tensile stress. Class 1 piping is insulated with NUKON non-metallic insulation determined by chemical analysis to be in compliance with NRC Regulatory Guide 1.36. Class 2 piping is not insulated. It is assumed, based on the plant service history evaluation, that no outside piping surfaces are exposed to wetting from concentrated chloride bearing environments. Therefore, based on the EPRI ECSCC criteria shown in Table A-6 of Appendix A, it is concluded that Main Steam piping is not considered susceptible to ECSCC.

3.2.7 Feedwater System

All Feedwater piping is made of carbon steel. The operating temperature is 315°F. The piping is conservatively assumed to be under tensile stress. All piping is insulated with NUKON non-metallic insulation determined by chemical analysis to be in compliance with NRC Regulatory Guide 1.36. It is assumed, based on the plant service history evaluation, that no outside piping surfaces are exposed to wetting from concentrated chloride bearing environments. Therefore, based on the EPRI ECSCC criteria shown in Table A-7 of Appendix A, it is concluded that Feedwater piping is not considered susceptible to ECSCC.

Table 3-1

Piping Materials and Conditions

System	System ID#	Size	Piping Class	Pipe Material(s)	Operating Temp	Insulation Type	Appendix A Table
Isolation Condenser	211	10"	1	A312 TP316 A358 TP316 A376 TP316	548 °F	NUKON	A-1
			2	SA312 TP316			
Core Spray	212	8"	1	A312 TP316 A358 TP316 A376 TP316	350 °F	NUKON	A-2
		10"	2	A106 Grade B			
Shutdown Cooling	214	14"	1	A312 TP316 A376 TP316 A106 Grade C	350 °F	NUKON	A-3
		8"	2	A106 Grade C			
Cleanup Demin.	215	6"	1	A312 TP316 A376 TP316	548 °F	NUKON	A-4
		20"	2	A106 Grade B	250 °F	None	
Recirc.	223	26"	1	A376 TP316	528 °F	NUKON	A-5
Main Steam	411	24"	1	A106 Grade C	540 °F	NUKON	A-6
		24"	2				
		8"/14"	2	A106 Grade B	400 °F	None	
Feedwater	422	10"/18"	1	A106 Grade C	315 °F	NUKON	A-7
		14"/18"/ 20"/24"	2				

4.0 SERVICE HISTORY REVIEW

To ensure that the evaluation performed in the previous section is consistent with the operating experience, a service history review was performed for the Class 1 and 2 systems at Oyster Creek.

Site documentation (MNCRs, CAPs and LERs) was reviewed for any history of piping degradation from the OD. No piping degradation from OD generated flaws initiated by chloride contamination was found. In addition, no outside surfaces of this Class 1 and 2 piping are exposed to wetting from concentrated chloride bearing environments in the Oyster Creek plant. As part of this review, a matrix of the various drywell leaks from valves and pumps was assembled. This includes the V-16-63 bonnet leak, EMRV pilot valve leakage, Recirculation pump flanges and seal leakage, and Containment spray initiation during plant operation. None of these systems contain significant amounts of chlorides that would damage the insulation or piping.

Another area for potential chloride contamination of the OD of the in-scope piping is from using the wrong (unapproved) chemicals on the piping during marking or cleaning. Oyster Creek has had a consumable materials chemical control program for many years that controls the use of chemicals within the plant area. This program controlled the use of lubricants, sealants, solvents, adhesives, markers and cleaning agent within various areas of the plant. This program refers to NEDE-31295P "BWR Operators Manual for Materials and Processes" which is the General Electric Company handbook for nuclear industry chemical control. Based on this program, it is reasonable to assume that chloride attack from use of chemicals on this piping has not occurred.

5.0 SUMMARY AND CONCLUSIONS

In this evaluation report, a degradation mechanism assessment has been performed in support of eliminating the surface exams for the Class 1 and 2 piping at Oyster Creek. The evaluation was performed using the guidelines provided in EPRI Report 112657, Revision B-A. It was established that the only mechanism that affects the outside surface of the pipe is External Chloride Stress Corrosion Cracking (ECSCC).

The evaluation indicated that most of the piping is insulated with NUKON non-metallic insulation which has been determined by chemical analysis to be in compliance with NRC Regulatory Guide 1.36. Hence, the insulated piping is not considered susceptible to ECSCC. The portion of the piping that is not insulated is made of carbon steel, which is not susceptible to ECSCC.

In addition, a review [6] has been completed of Class 1 and 2 piping service history at Oyster Creek. This review did not identify any prior occurrence of ECSCC on the Class 1 and 2 systems confirming the absence of this mechanism for the Class 1 and 2 systems at Oyster Creek.

It is therefore concluded that the Class 1 and 2 piping at Oyster Creek considered in this evaluation is not susceptible to ECSCC. Since ECSCC is the only potential mechanism that can affect the external surface of the pipe, it can be further concluded that the outside surface of the pipe is free of any degradation mechanisms therefore supporting the elimination of the surface examinations for the evaluated piping.

6.0 REFERENCES

1. "Revised Risk-Informed Inservice Inspection Evaluation Procedure," EPRI Report 112657, Revision B-A, December 1999.
2. ASME Code Case N-663 "Alternative Requirements for Classes 1 and 2 Surface Examinations," Section XI, Division 1, Approved 9/17/2002.
3. Email from Gregory F. Harttraft (AmerGen) to Nathaniel G. Cofie (SI), "Re: Final Proposal for Damage Mechanism Evaluation, Attachment: OC DMA Design Inputs.doc," 5/22/2003 8:42 am, SI File No. OC-04Q-201.
4. AmerGen Engineering Standard ES-029, "Piping and Equipment Insulation Design," Revision 3, 2/5/2002, SI File No. OC-04Q-202.
5. GPU Nuclear Technical Specification SP-1302-32-019, "Nuclear Grade Fiberglass Insulation Systems, O.C.N.G.S. Drywell," Revision 2, 10/17/1985, SI File No. OC-04Q-203.
6. Email from Gregory F. Harttraft (AmerGen) to Nathaniel G. Cofie (SI), "Service History Eval, Attachment: OC DMA Pipe Service Hist Review.doc,", June 05, 2003 10:02 am, SI File No. OC-04Q-204.

APPENDIX A

DEGRADATION MECHANISM EVALUATION TABLES

Table A-1

Isolation Condenser System

Degradation Mechanism Assessment Worksheet						
No.	**Attributes to be Considered**	**Yes**	**No**	**N/C**	**N/A**	**Remarks**
ECSCC-1	austenitic stainless steel, and	☒	☐	☐	☐	All lines are stainless steel
ECSCC-2	operating temperature > 150°F, and	☒	☐	☐	☐	548°F
ECSCC-3	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-4	an outside piping surface is within five diameters of a probable leak path (e.g., valve stems) and is covered with non-metallic insulation that is not in compliance with Reg. Guide 1.36	☐	☒	☐	☐	Insulation in compliance with Reg. Guide 1.36
	OR					
ECSCC-5	austenitic stainless steel, and	☒	☐	☐	☐	All lines are stainless steel
ECSCC-6	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-7	an outside piping surface is exposed to wetting from concentrated chloride bearing environments (i.e., sea water, brackish water or brine)	☐	☒	☐	☐	No exposure (service history)
In conclusion, ECSCC degradation mechanism is not active in this piping.						

Table A-2

Core Spray System

Degradation Mechanism Assessment Worksheet						
No.	**Attributes to be Considered**	**Yes**	**No**	**N/C**	**N/A**	**Remarks**
ECSCC-1	austenitic stainless steel, and	☒	☐	☐	☐	8" line is stainless steel
ECSCC-2	operating temperature > 150°F, and	☒	☐	☐	☐	350°F
ECSCC-3	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-4	an outside piping surface is within five diameters of a probable leak path (e.g., valve stems) and is covered with non-metallic insulation that is not in compliance with Reg. Guide 1.36	☐	☒	☐	☐	Insulation in compliance with Reg. Guide 1.36
	OR					
ECSCC-5	austenitic stainless steel, and	☒	☐	☐	☐	8" line is stainless steel
ECSCC-6	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-7	an outside piping surface is exposed to wetting from concentrated chloride bearing environments (i.e., sea water, brackish water or brine)	☐	☒	☐	☐	No exposure (service history)
In conclusion, ECSCC degradation mechanism is not active in this piping.						

Table A-3

Shutdown Cooling System

Degradation Mechanism Assessment Worksheet						
No.	Attributes to be Considered	Yes	No	N/C	N/A	Remarks
ECSCC-1	austenitic stainless steel, and	☒	☐	☐	☐	Parts of 14" line are stainless steel
ECSCC-2	operating temperature > 150°F, and	☒	☐	☐	☐	350°F
ECSCC-3	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-4	an outside piping surface is within five diameters of a probable leak path (e.g., valve stems) and is covered with non-metallic insulation that is not in compliance with Reg. Guide 1.36	☐	☒	☐	☐	Insulation in compliance with Reg. Guide 1.36
	OR					
ECSCC-5	austenitic stainless steel, and	☒	☐	☐	☐	Parts of 14" line are stainless steel
ECSCC-6	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-7	an outside piping surface is exposed to wetting from concentrated chloride bearing environments (i.e., sea water, brackish water or brine)	☐	☒	☐	☐	No exposure (service history)
In conclusion, ECSCC degradation mechanism is not active in this piping.						

Table A-4

Cleanup Demineralization System

Degradation Mechanism Assessment Worksheet						
No.	Attributes to be Considered	Yes	No	N/C	N/A	Remarks
ECSCC-1	austenitic stainless steel, and	☒	☐	☐	☐	6" line is stainless steel
ECSCC-2	operating temperature > 150°F, and	☒	☐	☐	☐	548°F
ECSCC-3	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-4	an outside piping surface is within five diameters of a probable leak path (e.g., valve stems) and is covered with non-metallic insulation that is not in compliance with Reg. Guide 1.36	☐	☒	☐	☐	Insulation in compliance with Reg. Guide 1.36 (20" carbon steel line is uninsulated)
	OR					
ECSCC-5	austenitic stainless steel, and	☒	☐	☐	☐	6" line is stainless steel
ECSCC-6	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-7	an outside piping surface is exposed to wetting from concentrated chloride bearing environments (i.e., sea water, brackish water or brine)	☐	☒	☐	☐	No exposure (service history)
In conclusion, ECSCC degradation mechanism is not active in this piping.						

Table A-5

Reactor Recirculation System

Degradation Mechanism Assessment Worksheet						
No.	**Attributes to be Considered**	**Yes**	**No**	**N/C**	**N/A**	**Remarks**
ECSCC-1	*austenitic stainless steel, and*	☒	☐	☐	☐	All piping is stainless steel
ECSCC-2	*operating temperature > 150°F, and*	☒	☐	☐	☐	528°F
ECSCC-3	*tensile stress is present, and*	☒	☐	☐	☐	Assumed
ECSCC-4	*an outside piping surface is within five diameters of a probable leak path (e.g., valve stems) and is covered with non-metallic insulation that is not in compliance with Reg. Guide 1.36*	☐	☒	☐	☐	Insulation in compliance with Reg. Guide 1.36
	OR					
ECSCC-5	*austenitic stainless steel, and*	☒	☐	☐	☐	All piping is stainless steel
ECSCC-6	*tensile stress is present, and*	☒	☐	☐	☐	Assumed
ECSCC-7	*an outside piping surface is exposed to wetting from concentrated chloride bearing environments (i.e., sea water, brackish water or brine)*	☐	☒	☐	☐	No exposure (service history)
In conclusion, ECSCC degradation mechanism is not active in this piping.						

Table A-6

Main Steam System

Degradation Mechanism Assessment Worksheet						
No.	**Attributes to be Considered**	**Yes**	**No**	**N/C**	**N/A**	**Remarks**
ECSCC-1	*austenitic stainless steel, and*	☐	☒	☐	☐	All lines are carbon steel
ECSCC-2	*operating temperature > 150°F, and*	☒	☐	☐	☐	540°F and 400°F
ECSCC-3	*tensile stress is present, and*	☒	☐	☐	☐	Assumed
ECSCC-4	*an outside piping surface is within five diameters of a probable leak path (e.g., valve stems) and is covered with non-metallic insulation that is not in compliance with Reg. Guide 1.36*	☐	☒	☐	☐	Insulation in compliance with Reg. Guide 1.36 (8" and 14" lines are uninsulated)
	OR					
ECSCC-5	*austenitic stainless steel, and*	☐	☒	☐	☐	All lines are carbon steel
ECSCC-6	*tensile stress is present, and*	☒	☐	☐	☐	Assumed
ECSCC-7	*an outside piping surface is exposed to wetting from concentrated chloride bearing environments (i.e., sea water, brackish water or brine)*	☐	☒	☐	☐	No exposure (service history)
In conclusion, ECSCC degradation mechanism is not active in this piping.						

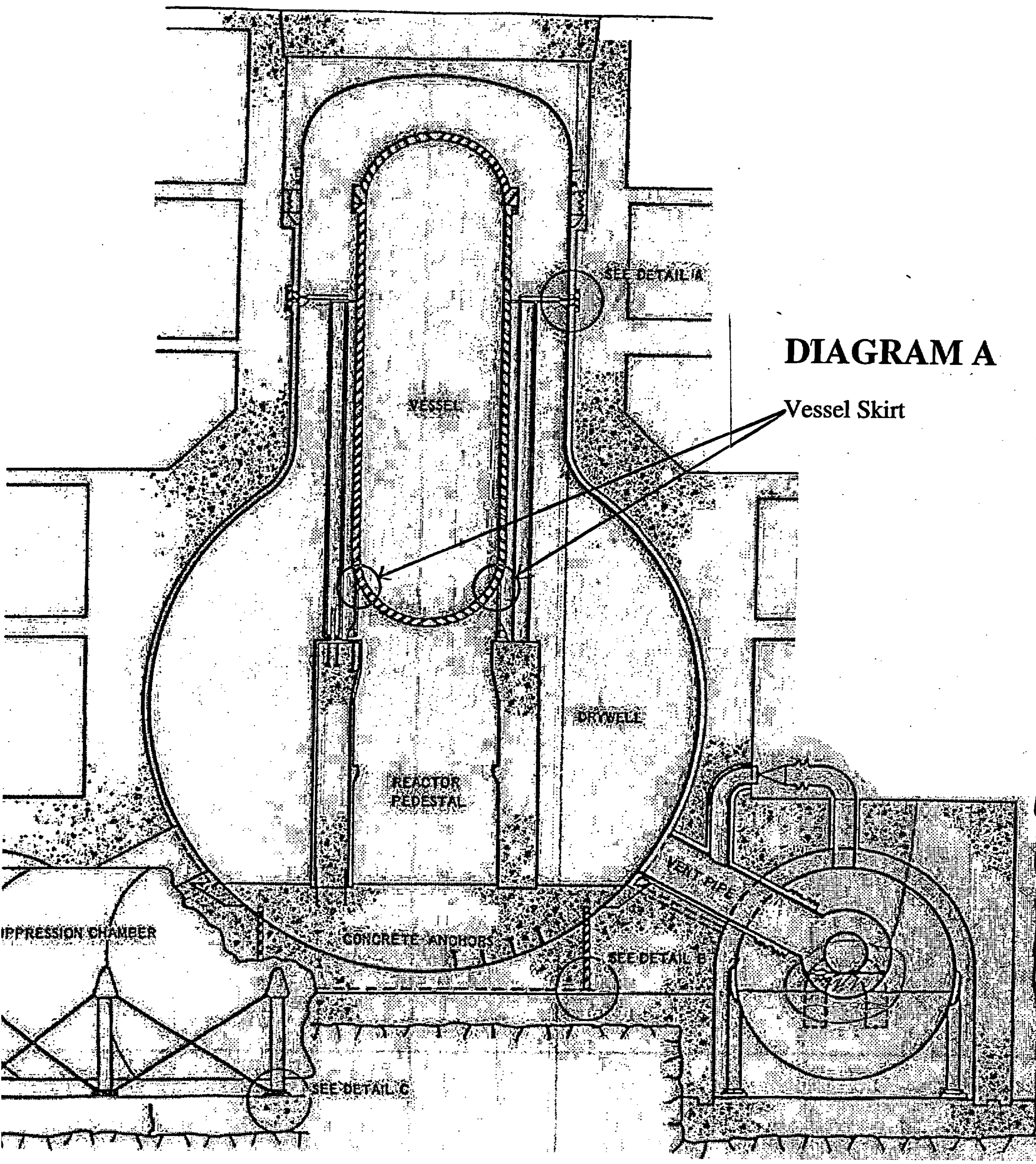
Table A-7

Feedwater System

Degradation Mechanism Assessment Worksheet						
No.	**Attributes to be Considered**	**Yes**	**No**	**N/C**	**N/A**	**Remarks**
ECSCC-1	austenitic stainless steel, and	☐	☒	☐	☐	All lines are carbon steel
ECSCC-2	operating temperature > 150°F, and	☒	☐	☐	☐	315°F
ECSCC-3	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-4	an outside piping surface is within five diameters of a probable leak path (e.g., valve stems) and is covered with non-metallic insulation that is not in compliance with Reg. Guide 1.36	☐	☒	☐	☐	Insulation in compliance with Reg. Guide 1.36
	OR					
ECSCC-5	austenitic stainless steel, and	☐	☒	☐	☐	All lines are carbon steel
ECSCC-6	tensile stress is present, and	☒	☐	☐	☐	Assumed
ECSCC-7	an outside piping surface is exposed to wetting from concentrated chloride bearing environments (i.e., sea water, brackish water or brine)	☐	☒	☐	☐	No exposure (service history)
In conclusion, ECSCC degradation mechanism is not active in this piping.						

DIAGRAMS A, B, C, and D

IT-S~~UPP~~ORT AND ANCHORAGE



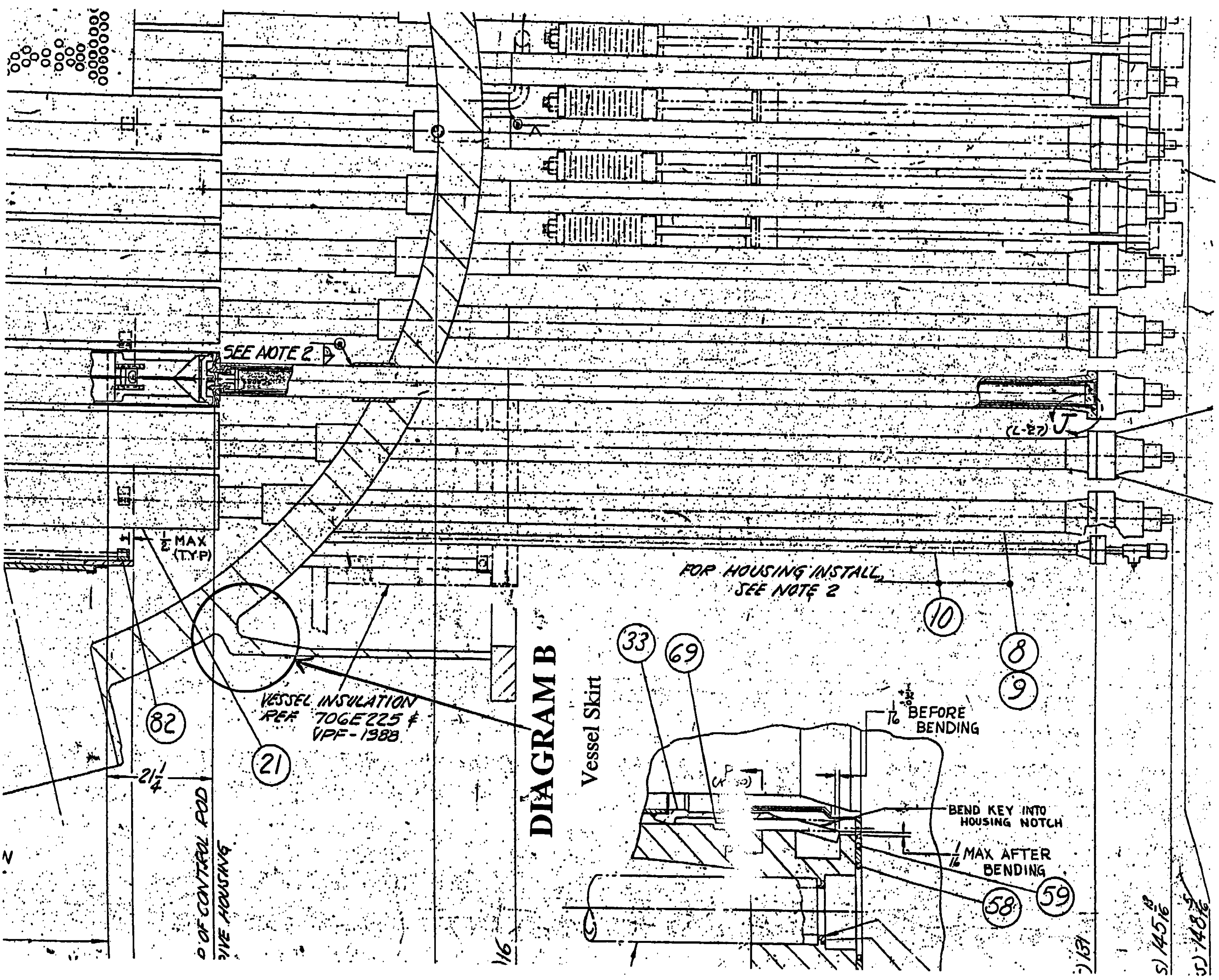


DIAGRAM B
Vessel Skirt

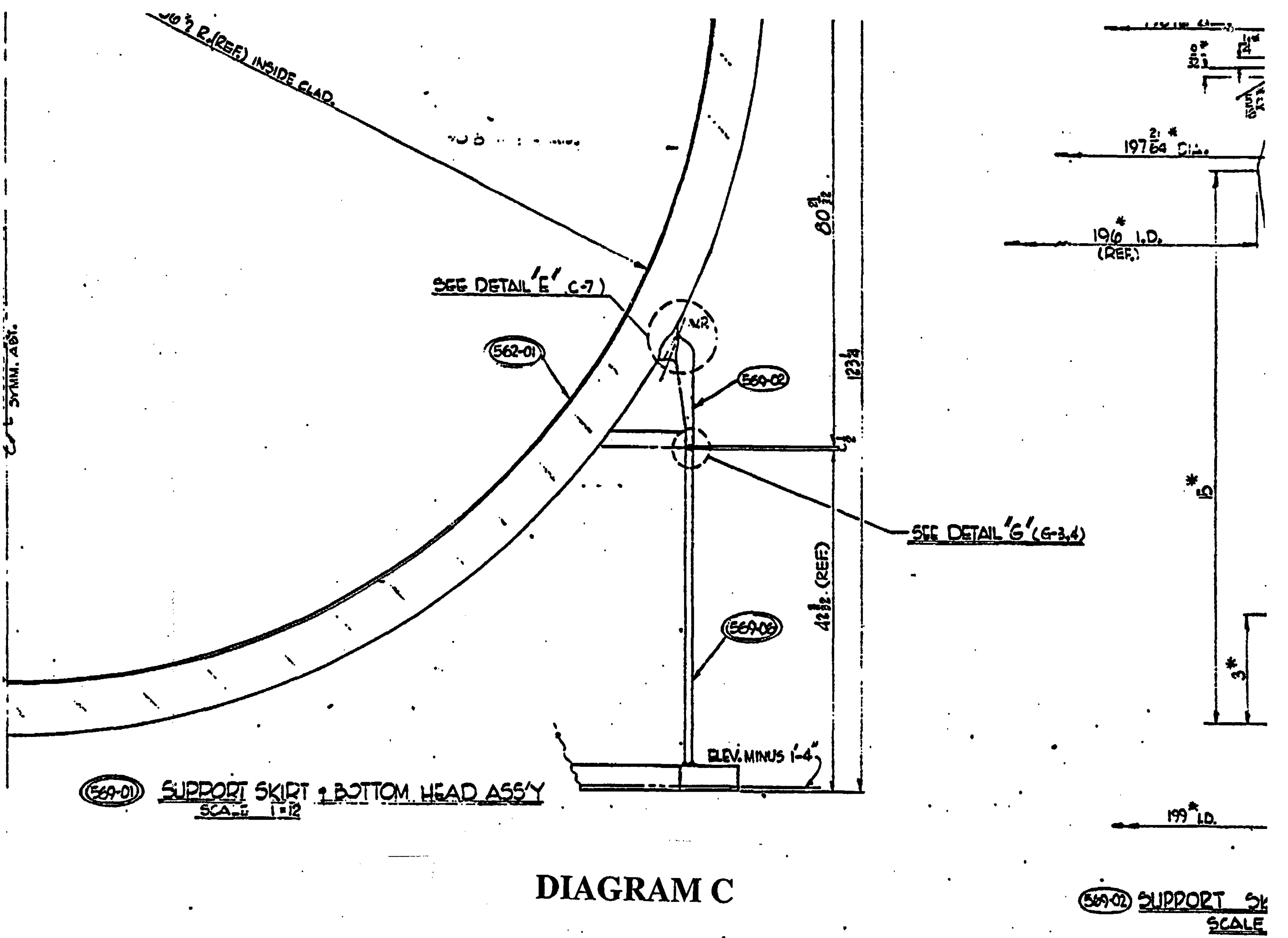
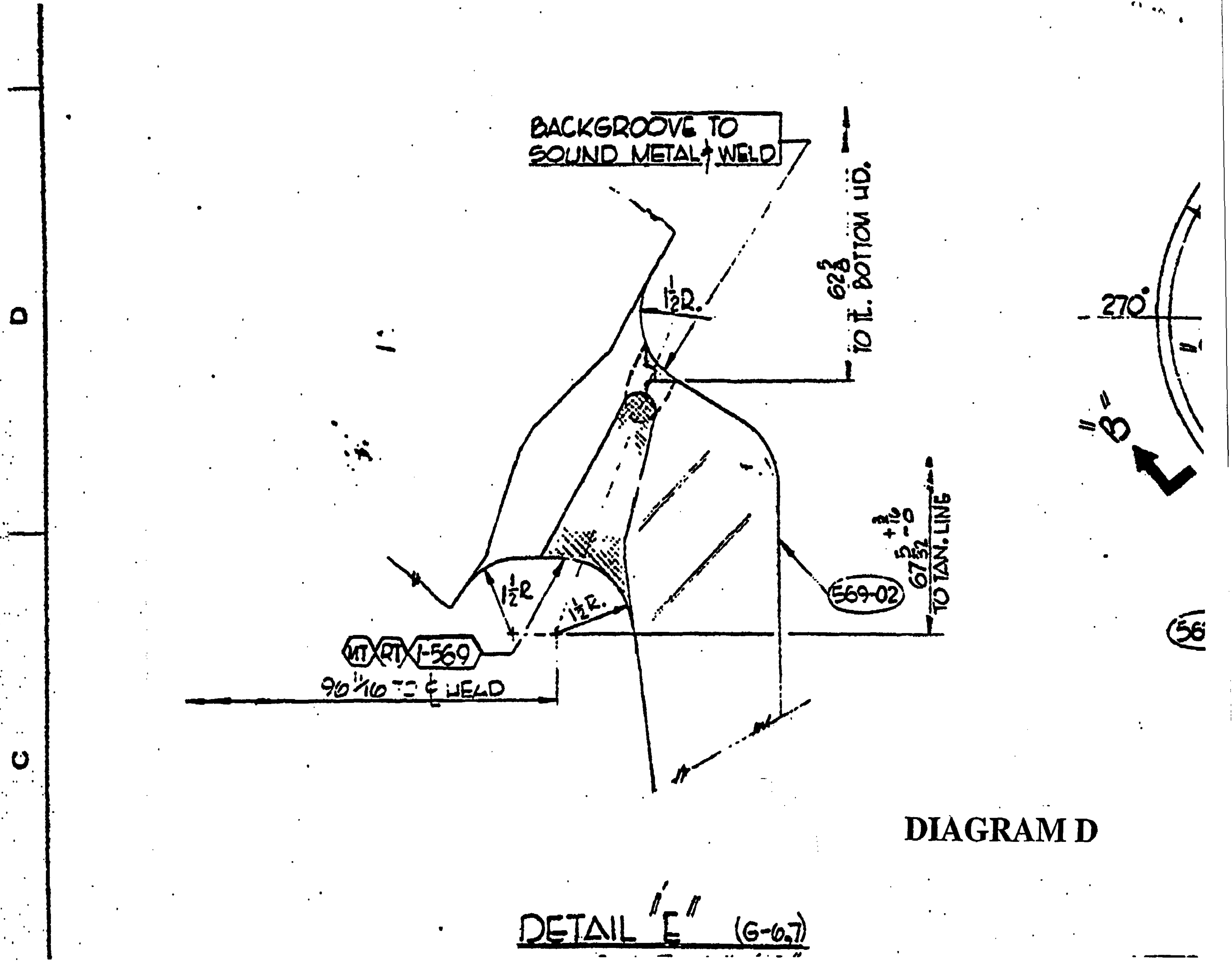

R.(REF) INSIDE CLAD.
SEE DETAIL 'E' (C-7)
562-01
569-02
SEE DETAIL 'G' (G-3,4)
569-03
ELEV. MINUS 1'-4"
569-01
SUPPORT SKIRT & BOTTOM HEAD ASS'Y
SCALE 1=12
SYMM. ABT.
196 I.D. (REF.)
199 I.D.
569-02
SUPPORT SK
SCALE

DIAGRAM C



BACKGROOVE TO SOUND METAL & WELD
1½R.
62⅜ TO ℄ BOTTOM HD.
270°
"B"
1½R
1½R.
569-02
67 5/32 +1/16 -0 TO TAN. LINE
MT RT 1-569
90 11/16 TO ℄ WELD
D
C
DETAIL "E" (G-6,7)

DIAGRAM D