UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

March 27, 2000

LICENSEES: Baltimore Gas and Electric (BGE) Company

FACILITIES: Calvert Cliffs Nuclear Power Plant, (CCNPP) Unit Nos. 1 and 2

SUBJECT: SUMMARY OF OCTOBER 12, 1999, MEETING WITH BGE REGARDING LICENSE RENEWAL ACTIVITIES FOR CCNPP UNIT NOS. 1 AND 2

On October 12, 1999, the U. S. Nuclear Regulatory Commission (NRC) staff held a public meeting with representatives of BGE and Duke at Rockville, Maryland, to discuss the status of the NRC's review of BGE's license renewal application (LRA) for the CCNPP Units 1 and 2. Enclosure 1 to this meeting summary provides a list of the meeting attendees. Enclosure 2 provides a copy of slides that were used by NRC and BGE to summarize the status of the BGE review.

The NRC staff summarized the status regarding the resolution of the open items and confirmatory items as outlined in the March 21, 1999, safety evaluation report related (SER) to license renewal of the CCNPP Units 1 and 2 (Enclosure 2). The staff also provided the status of the license renewal generic issues applicable to the CCNPP review (Enclosure 2). A copy of facsimiles sent to the staff by BGE to facilitate resolving the open and confirmatory items was also made available during the meeting (Enclosure 2). The staff discussed the open item related updating the final safety analysis report (FSAR) content with respect to aging management programs (AMPs) for license renewal. The staff recalled that the specific options for resolving this open item were proposed to BGE in an August 28, 1999, monthly management meeting and that BGE had agreed to develop a list of program features in accordance with option 3. The staff thanked BGE for providing its examples regarding the level of detail for updating the FSAR with respect to AMPs for three systems. The staff stated that considering the examples provided by BGE it had developed examples for 3 systems using the staff conclusions described in the SER, provided in Enclosure 2, regarding the appropriate level of detail for updating the FSAR. The staff then requested that BGE use these examples to develop the complete list of AMP attributes to be included in the FSAR and submit the list to the NRC so that the staff could verify its accuracy against the safety evaluation report. The staff added that to ensure issuance of a revised SER on schedule it needed BGE's submittal no later than October 22, 1999. The staff also mentioned that the SER concurrence process had the potential to identify additional questions that might require BGE management support to resolve. They concluded by noting that overall communications to resolve open and confirmatory items were good and contributed to effectively resolving these items.

BGE opened by commending that the staff's recent efforts to work towards closure of the open and confirmatory items over the past few weeks were an example of excellent project management. Based on the interactions on the open item related to the FSAR update, BGE considered it had committed to provide information to satisfy the requirements of the NRR Office Letter 805 by agreeing to provide a list of AMP attributes as the staff has requested, using the staff's examples as a guideline, by mid-November 1999. The staff added that the list of AMP attributes would be a way that the staff could memorialize its conclusions and it would rely on the list to verify BGE's process would incorporate the commitments. BGE stated that the staff should rely on their LRA correspondence record and not just the list that they expect to provide the staff. They staff stated that the ultimate use of the list was to identify to the Commission that this is how the current licensing basis final safety analysis report summary description is going to be revised by the process. BGE stated that it was their belief that the correspondence record supporting their application was binding and not the list the staff requested they provide.

BGE stated that it continued to understand the staff requirement with respect to requesting the list of AMP attributes and that since this is a new process it required flexibility; however, it was BGE's opinion that there was an existing process that also needed to be recognized. BGE stated that while they were agreeing to provide the list to identify major AMPs in the record, because of timing BGE would not be able to submit the list under oath and affirmation. BGE added that how the list was used was an important issue for the new license. Nevertheless, BGE stated that it needed to be recognized that the list will not truncate their current internal process for controlling information. The staff suggested that perhaps this might be a policy issue for the Commission to provide direction on bringing harmony between the license renewal rule (10 CFR Part 54) and 10 CFR Part 50.71(e).

/RA/

David L. Solorio, Project Manager
License Renewal and Standardization Branch
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket Nos. 50-317 and 50-318 (BGE)

Enclosures: 1. List of Attendees
2. Meeting Slides

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description is going to be revised by the process. BGE stated that it was their belief that the correspondence record supporting their application was binding and not the list the staff requested they provide.

BGE stated that it continued to understand the staff requirement with respect to requesting the list of AMP attributes and that since this is a new process it required flexibility; however, it was BGE's opinion that there was an existing process that also needed to be recognized. BGE stated that while they were agreeing to provide the list to identify major AMPs in the record, because of timing BGE would not be able to submit the list under oath and affirmation. BGE added that how the list was used was an important issue for the new license. Nevertheless, BGE stated that it needed to be recognized that the list will not truncate their current internal process for controlling information. The staff suggested that perhaps this might be a policy issue for the Commission to provide direction on bringing harmony between the license renewal rule (10 CFR Part 54) and 10 CFR Part 50.71(e).

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NRC MANAGEMENT MEETING
TO DISCUSS STATUS OF
BGE LRA REVIEW
OCTOBER 12, 1999

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ROBERT GILL	DUKE ENERGY
NANCY CHAPMAN	SERCH\BECHTEL
STEPHEN KOENICK	NRC\NRR\DRIP\RLSB
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DAVID LEWIS	SHAW PITTMAN
JACK STROSNIDER	NRC\NRR\DE
PT KUO	NRC\NRR\DRIP\RLSB
WILLIAM BURTON	NRC\NRR\DRIP\RLSB
GOUTAM BAGCHI	NRC\NRR\DE\
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SAM LEE	NRC\NRR\DRIP\RLSB
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STEVE HOFFMAN	NRC\NRR\DRIP\RLSB

Enclosure 1

Meeting Slides

Enclosure 2

Meeting Agenda
October 12, 1999

- NRC Introductory Remarks
- BGE Introductory Remarks
- Discuss Status of August 12, 1999, Letter Regarding Open Item and Confirmatory Items Status
- Discuss Status of Open Item Related to Information to be Captured in FSAR
- Closing Remarks BGE & NRC

Status of Calvert Cliffs Safety Evaluation Report Open & Confirmatory Items

October 12, 1999

Chris Grimes, Branch Chief, License Renewal & Standardization Branch
David Solorio, Project Manager, License Renewal & Standardization Branch

Meeting Agenda

Status of Calvert Cliffs Safety Evaluation Report (SER)

- Status regarding August 12, 1999, letter related to:
  - Open Items (OIs)
  - Confirmatory Items (CI)
  - New Item
  - License Renewal Generic Issues
- Information to be added to Final Safety Analysis Report (FSAR) - OI

Status of August 12, 1999 Letter on OIs and CIs

Open Items

- Stress Corrosion Cracking Plausibility in Reactor Coolant System (3.2.3.3.1.1-2) - **Resolved**, pending October submittal
- Stress Corrosion Cracking Aging Management Program for Reactor Pressure Vessel Seal Leakoff Line (3.2.3.2.1-2) - **Resolved**, pending October submittal
- Inspections of Small Bore Reactor Coolant System Piping (3.2.3.2.1-4) -**Resolved**, pending October submittal
- Tendon Prestress Curves Extrapolated to 60 Years (3.10.3.2.1) - **Resolved**
- Time Limited Aging Analysis for Tendon Prestressing (4.1.3-2), **Resolved**
- *Pressurizer Cladding Cracking (3.2.3.2.1-3) - **Resolved**, pending October submittal*

Status of August 12, 1999 Letter on OIs and CIs - continued

Confirmatory Items

- Application of BGE's Appendix B Program to Non-Safety-Related Components (3.1.5.3-1) - **Resolved**
- Aging Management of Control Element Assembly Shroud Bolts (3.2.3.2.1-4) - **Resolved**, pending October submittal

Status of August 12, 1999 Letter on OIs and CIs - continued

New Issue

– Void Swelling (NEW) - **<u>Resolved</u>**, pending October submittal

Status of August 12, 1999 Letter on OIs and CIs - continued

License Renewal Generic Issues

- Cast Austenitic Stainless Steel (also related to CI 3.2.3.2.1-1) -**Resolved**, pending October submittal
- Scoping (OIs realted to SBO Building [2.2.3.8-1] and HVAC ducting [2.2.3.23.2.1-1]) -both OIs **Resolved**
  - Waiting for SBO Building Aging Management Review Results
  - Sent 8/5/99 letter to NEI regarding scoping
- Heat Exchanger Function, NRC hasn't identified any additional BGE action
- Complex Assemblies, NRC hasn't identified any additional BGE action

Status of August 12, 1999 Letter on OIs and CIs - continued

Open Item - Timing and Content of FSAR Update

- Options outlined at 8/28/98 Public Meeting
- Remaining discussions regarding content in terms of description of commitments
  - BGE provided sample list for three systems outlining programs to be added to FSAR during normal update process
  - NRC developed sample list for three different types of program commitments related to three different LRA sections

Status of August 12, 1999 Letter on OIs and CIs - continued

Closing Remarks

- Overall communications to obtain clarification were effective in resolving OIs & CIs
- Probably could have resolved several items much earlier
- Need October submittal October 22, 1999 to preclude delay in issuing SER
- SER concurrence reviews have the potential to require additional interaction

Summary of LRA Review Activities

Schedule

Calvert Cliffs Milestones	Target
Applicant & NRC Meeting to Resolve Outstanding OI/CI	10/12/99
Applicant & NRC Meeting to Resolve Outstanding FSAR CI	10/12/99
NRC Develop Renewed License Format	10/20/99
Forward closure of OI/CI to ACRS	11/1/99
ACRS subcommittee SER OI/CI Review	11/15/99
Staff Issue SER & FSEIS	11/16/99
Meeting with Applicant on Form of New License	11/17/99
Conduct 3rd License Renewal Inspection	12/3/99
ACRS Full Committee SER OI/CI Review	12/4/99
ACRS Letter	12/10/99
Issue SER as NUREG-1705	12/20/99
Regional Administrator Letter	12/31/99
Commission Paper with Staff Recommendation	1/14/00
Commission Meeting (if requested)	3/15/00
Commission Decision	3/27/00
Renewed License Issued	4/3/00

Sample List of BGE Programs Credited for Aging Management for License Renewal

System	Components	Aging Effect	Program	Description of Program	Implementation Schedule
Containment spray	PP, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPS, RVs, TEs, and TIs	General corrosion, crevice corrosion, and pitting of internal surfaces	Age-related degradation inspection (ARDI) program	To verify the effectiveness of its chemistry program and to supplement the limited scope of local leak rate test program, one-time inspection of internal surfaces of components (using visual inspection) at the most susceptible locations is performed to ensure that degradation is not occurring as a result of corrosion. When the program development is completed, the program will have the following attributes: (1) program scope, (2) parameter monitored or inspected, (3) detection of aging effects using qualified inspection method, and (4) acceptance criteria.	To be implemented by 2003
Containment spray	PP, CKVs, CVs, HVs, HXs, MOVs, and PUMPS	General corrosion	Boric acid corrosion inspection program	The program consists of: (1) visual inspection of external surfaces that are potentially exposed to borated water for leaks, (2) timely discovery of leak path and removal of the boric acid residues, (3) assessment of the damage, and (4) follow up inspection for adequacy.	Existing program
Containment spray	PP, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPS, RVs, TEs, and TIs	General corrosion, crevice corrosion, and pitting of internal surfaces	Chemistry program	To mitigate aging effects on internal surfaces that are exposed to borated water as process fluid, chemistry programs are used to control primary water chemistry for impurities (chloride, fluoride, and sulfate) that accelerate corrosion.	Existing program

System	Components	Aging Effect	Program	Description of Program	Implementation Schedule
Reactor vessel	Reactor vessel	Neutron embrittlement	Comprehensive reactor vessel surveillance program	Irradiating and testing of metallurgical samples are used to monitor the progress of neutron embrittlement as a function of neutron fluence. The current program is in accordance with ASTM E 185. The program consists of 6 capsules in each unit, with 2 capsules tested, 3 capsules to be tested, and one standby capsule. The withdrawal schedule will be revised to provide data at neutron fluence equal to or greater than the projected peak fluence at the end of the license renewal period. If the last capsule is withdrawn before year 55, will establish reactor vessel neutron environment conditions applicable to the surveillance data. If the plant operates outside of the limits established by these conditions, will inform the NRC and determine the impact of the condition on reactor vessel integrity. If the last capsule is withdrawn before year 55, will install neutron dosimetry to permit tracking of the fluence to the reactor vessel.	The surveillance capsule withdrawal schedule will be revised by 2003.

System	Components	Aging Effect	Program	Description of Program	Implementation Schedule
Reactor coolant system	Pipes, elbows, nozzles	Fatigue	Fatigue monitoring program (FMP)	In order not to exceed the design limit on fatigue usage and the number of design cycles, FMP monitors and tracks the number of critical thermal and pressure test transients, and monitors the cycles for the selected RCS components. The FMP will be modified to monitor a sample of components with high fatigue usage factors for the effects on the fatigue life. The following bounding locations are included in the evaluation: charging system piping, charging inlet nozzles, charging inlet nozzle piping, hot leg surge nozzle, pressurizer spray system piping, pressurizer spray nozzle, pressurizer surge line, pressurizer surge nozzle, pressurizer surge line elbow, SI nozzle, shutdown cooling outlet nozzle. The FMP will assess the effect of the environment using statistical correlations developed by Argonne National Laboratory (ANL) in NUREG/CR-5704. The modified FMP will use the ANL statistical correlations to calculate an effective environmental factor to account for the reduction in fatigue life due to the reactor water environment. This factor will be applied to fatigue loads where the specified threshold criteria for strain rate and temperature have been exceeded. A factor of 1.5 will be used for evaluation of austenitic stainless steel components.	Program will be modified by 2014

10/8/99 VERSION

CASS Question #2: Provide a description of the plans for susceptible piping, base metal - inspect, replace, or what? Regarding the surge line, are there any activities related to NRC Bulletin 88-11 that effectively serve as aging management for the surge line?

Components which do not meet the screening criteria described in reference 1 will be:

1. Subject to an augmented inspection combined with a flaw tolerance evaluation, or,
2. A full leak-before-break evaluation will be performed to prove that current inspection requirements are adequate to prevent catastrophic failure, or,
3. Replaced.

Augmented Inspection

When option 1 (augmented inspection combined with flaw tolerance evaluation) is selected, components will be inspected as if they were pressure retaining welds in ASME Section XI category B-L-1, B-M-1, or BJ components. Generally, this will be a volumetric examination. If available inspection technology does not permit a volumetric examination, an alternative approach similar to that described in Code Case N-481 will be used to manage thermal aging embrittlement of the component.

The acceptance criteria for the augmented inspection will be determined by the outcome of a flaw tolerance evaluation. ASME Section XI, 1989 edition, article IWB-3640, provides two different sets of acceptable flaw sizes. Base metal, GTAW welds, and GMAW welds have larger acceptable flaw sizes, while SMAW and SAW welds have smaller acceptable flaw sizes reflecting the lower toughness of these types of welds. A fracture mechanics analysis in accordance with the methods described in Appendix K will be conducted to show that the component will experience ductile failure rather than unstable crack extension with the assumed flaw size. The fracture toughness properties (J-R curve) used for the fracture mechanics analysis will be estimated for each component using the method of reference 2 or equivalent. (These analyses will be performed for non-niobium containing components with less than 25% ferrite content. For components containing niobium or components with greater than 25 % ferrite, the actual fracture toughness properties will have to be determined on a case by case basis before the analysis could be completed.) If the fracture mechanics analysis shows a large flaw size appropriate to GTAW, GMAW, or base metal is *stable under all anticipated normal and accident loadings*, the larger flaw sizes will be applied as acceptance criteria for the inspection. If the larger flaws are found to be unstable under the anticipated loadings, the smaller flaw sizes appropriate to SAW and SMAW welds will be used as acceptance criteria for the inspection. The acceptable flaw sizes used for the flaw tolerance evaluation will be in accordance with ASME Section XI, 1989 edition, article IWB-3640, or the equivalent article in a later approved edition of ASME Section XI.

changed changed

In extrer cases where the allowable flaw size is too small to detect with available technology, compone..ts will be replaced. However, such results are not expected.

Regarding the surge line, activities related to NRC Bulletin 88-11 may effectively serve as aging management for the surge line. BGE is currently awaiting ASME development of guidance for inspecting such piping for thermal fatigue. Once ASME guidance is provided BGE intends to determine the extent of inspections to be conducted.

References

10/8/99 VERSION

CASS Question 1: Provide the basis for the cut off of the 15 KSI Tensile Stress for plausibility of thermal aging in reactor vessel components. This should be identified as a cut off in the significance of the impact of thermal aging, not plausibility of the ARDM.

Response:

The selection of 15 ksi as a reasonably low tensile stress was somewhat arbitrary, but represents approximately one-half the yield strength of the material. BGE has revised this value as discussed below.

The components that are manufactured from CASS and are subjected to both thermal and neutron embrittlement are CEA shrouds and the core support columns in the reactor vessel internals. It is not currently possible to develop screening criteria for determining actual material property degradation of these components. Instead, these components will be screened to determine whether they are subjected to significant tensile stress during normal and upset operation.

For the CASS components subject to both thermal and neutron embrittlement, the loads applied to the components during normal and upset operation will be determined. If the maximum applied load anywhere on the component is less than approximately 5 ksi, then the no further analyses will be performed, and the effects of the embrittlement will be determined to be inconsequential.

For the subject CASS components that do experience tensile stresses exceeding 5 ksi under any design basis conditions, the operating history of the components will be reviewed to determine whether any such conditions have ever happened. As long as the component never experiences an event or condition that imposes a tensile stress that exceeds approximately 5 ksi, the effects of the embrittlement will be determined to be inconsequential.

changed For the subject CASS components that actually experience tensile stresses that exceed 5 ksi, an enhanced VT-1 inspection will be performed. BGE will demonstrated that the enhanced VT-1 technique is capable of resolving relevant indications on cast surfaces. If BGE is unable to demonstrate the enhanced VT-1 technique is applicable to cast surfaces then an alternative qualified technique will be used. BGE will changed continue to participate in industry programs that are currently underway to develop ultrasonic inspection methods for CASS, and could use ultrasonic techniques in lieu of surface techniques.

BGE will also follow industry programs that evaluate the combined effects of neutron and thermal embrittlement and modify this program accordingly.

1. Letter from Mr. C. H. Cruse to NRC dated July 2, 1999, re: Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & ; Docket Nos. 50-317 & 50-318 Response to License Renewal Safety Evaluation Report

2. Chopra, O. K., Shack, W. J., "Assessment of Thermal Aging Embrittlement of Cast Stainless Steels", NUREG/CR-6177, ANL-94/2, May 1994

10/8/99 VERSION

DRAFT

Regarding Void Swelling

Reference (xx) requested interaction regarding void swelling and BGE briefly discussed this issue as Item #8 in Reference (yy). Reference (zz) further discussed void swelling and indicated that void swelling needs to be to be included in BGE's license renewal application. In response, while we maintain that void swelling is not plausible:

- BGE agrees to participate in industry programs to address the significance of void swelling.
- Prior to year 40, if BGE determines that void selling is a significant issue in the renewal term, BGE agrees to develop a sufficient inspection program (including the basis, methods, locations to be examined, timing frequency and acceptance criteria) for management of the issue based upon the results of the industry programs, and performed in conjunction with the 10-year ISI program. changed
- If BGE has made its determination far enough in advance of the end of the current license period BGE will implement the inspection program prior to the end of that period. Otherwise, the program will be implemented as soon a practicable thereafter.

changed

References:

xx – NRC Aug 12 letter
yy – BGE Sept 28 letter
zz – NRC Sept 30 letter

<u>CASS Question 1</u>: *Provide the basis for the cut off of the 15 KSI Tensile Stress for plausibility of thermal aging in reactor vessel components. This should be identified as a cut off in the significance of the impact of thermal aging, not plausibility of the ARDM.*

Response:

The selection of 15 ksi as a reasonably low tensile stress was somewhat arbitrary, but represents approximately one-half the yield strength of the material. BGE has revised this value as discussed below.

The components that are manufactured from CASS and are subjected to both thermal and neutron embrittlement are CEA shrouds and the core support columns in the reactor vessel internals. It is not currently possible to develop screening criteria for determining actual material property degradation of these components. Instead, these components will be screened to determine whether they are subjected to significant tensile stress during normal and upset operation.

For the CASS components subject to both thermal and neutron embrittlement, the loads applied to the components during normal and upset operation will be determined. If the maximum applied load anywhere on the component is less than approximately 5 ksi, then the no further analyses will be performed, and the effects of the embrittlement will be determined to be inconsequential.

For the subject CASS components that do experience tensile stresses exceeding 5 ksi under any design basis conditions, the operating history of the components will be reviewed to determine whether any such conditions have ever happened. As long as the component never experiences an event or condition that imposes a tensile stress that exceeds approximately 5 ksi, the effects of the embrittlement will be determined to be inconsequential.

For the subject CASS components that actually experience tensile stresses that exceed 5 ksi, a visual inspection technique capable of resolving relevant defects will be developed, qualified, and applied. The inspection technique may be similar to the enhanced VT-1 technique, if it can be shown that this technique will work on cast surfaces. BGE will continue to participate in industry programs that are currently underway to develop ultrasonic inspection methods for CASS, and could use ultrasonic techniques in lieu of surface techniques.

BGE will also follow industry programs that evaluate the combined effects of neutron and thermal embrittlement and modify this program accordingly.

CASS Question #2: Provide a description of the plans for susceptible piping, base metal - inspect, replace, or what? Regarding the surge line, are there any activities related to NRC Bulletin 88-11 that effectively serve as aging management for the surge line?

Components which do not meet the screening criteria described in reference 1 will be:

1. Subject to an augmented inspection combined with a flaw tolerance evaluation, or,
2. A full leak-before-break evaluation will be performed to prove that current inspection requirements are adequate to prevent catastrophic failure, or,
3. Replaced.

Augmented Inspection

When option 1 (augmented inspection combined with flaw tolerance evaluation) is selected, components will be inspected as if they were pressure retaining welds in ASME Section XI category B-L-1, B-M-1, or BJ components. Generally, this will be a volumetric examination. If available inspection technology does not permit a volumetric examination, an alternative approach similar to that described in Code Case N-481 will be used to manage thermal aging embrittlement of the component.

The acceptance criteria for the augmented inspection will be determined by the outcome of a flaw tolerance evaluation. ASME Section XI, 1989 edition, article IWB-3640, provides two different sets of acceptable flaw sizes. Base metal, GTAW welds, and GMAW welds have larger acceptable flaw sizes, while SMAW and SAW welds have smaller acceptable flaw sizes reflecting the lower toughness of these types of welds. A limit load analysis will be conducted to show that the component will experience ductile failure rather than unstable crack extension with the assumed flaw size. The fracture toughness properties (J-R curve) used for the limit load analyses will be estimated for each component using the method of reference 2 or equivalent. If the limit load analysis shows a large flaw size appropriate to GTAW, GMAW, or base metal is *stable under all anticipated normal and accident loadings*, the larger flaw sizes will be applied as acceptance criteria for the inspection. If the larger flaws are found to be unstable under the anticipated loadings, the smaller flaw sizes appropriate to SAW and SMAW welds will be used as acceptance criteria for the inspection. The acceptable flaw sizes used for the flaw tolerance evaluation will be in accordance with ASME Section XI, 1989 edition, article IWB-3640, or the equivalent article in a later approved edition of ASME Section XI.

In extreme cases where the allowable flaw size is too small to detect with available technology, components will be replaced. However, such results are not expected.

Regarding the surge line, activities related to NRC Bulletin 88-11 may effectively serve as aging management for the surge line. BGE is currently awaiting ASME development of guidance for inspecting such piping for thermal fatigue. Once ASME guidance is provided BGE intends to determine the extent of inspections to be conducted.

References

1. Letter from Mr. C. H. Cruse to NRC dated July 2, 1999, re: Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & ; Docket Nos. 50-317 & 50-318 Response to License Renewal Safety Evaluation Report
2. Chopra, O. K., Shack, W. J., "Assessment of Thermal Aging Embrittlement of Cast Stainless Steels", NUREG/CR-6177, ANL-94/2, May 1994

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Reference (xx) requested interaction regarding void swelling and BGE briefly discussed this issue as Item #8 in Reference (yy). Reference (zz) further discussed void swelling and indicated that void swelling needs to be to be included in BGE's license renewal application. In response, while we maintain that void swelling is not plausible:

- BGE agrees to participate in industry programs to address the significance of void swelling.
- If BGE determ~~ines that void selling is a significant issue in the renewal ter~~m, BGE agrees to develop a sufficient inspection program (including the basis, methods, locations to be examined, timing frequency and acceptance criteria) for management of the issue based upon the results of the industry programs, and performed in conjunction with the 10-year ISI program.
- If BGE has made its determination far enough in advance of the end of the current license period BGE will implement the inspection program prior to the end of that period. Otherwise, the program will be implemented as soon a practicable thereafter.

References:

xx – NRC Aug 12 letter
yy – BGE Sept 28 letter
zz – NRC Sept 30 letter

BGE performed an aging management review evaluation for external surfaces of piping systems. The evaluation considered all combinations of materials and environments. The evaluation considered Calvert Cliffs practices that contain necessary guidance to retard or prevent corrosion on external surfaces of piping components. Those practices include painting and protective coatings application standards and thermal insulation standards.

The staff has indicated that TGSCC of the RCS piping would be the result of the presence of chlorides from insulation, concrete, or contaminated surfaces. However, water, residual stresses, and a specific temperature range are also required for the onset of chloride-induced TGSCC. To address the non-plausibility of TGSCC of RCS piping in more detail, two of the four contributing factors will be addressed – a source of chlorides and a source of water.

The following CCNPP documentation contains information relative to the insulation installed on RCS piping: Engineering Specification 6750-M-336, Specification for Reactor Coolant System and Steam Generators Insulation; Engineering Standard ES-015 (formerly DS-015), Thermal Insulation; and Dwg. 83240, Thermal Insulation for Piping and Equipment.

The first of these documents, Specification 6750-M-336, is the specification that was used for the original installation of the insulation on the RCS piping. The insulation originally installed on the system was either: (1) reflective insulation composed of all 304SS components, or (2) mineral wool sandwiched between an external stainless steel shell and an inner layer of stainless steel foil to cover all surfaces and edges. The specification required that the mineral wool material be treated with sodium silicate to act as an inhibitor against SCC and that the chloride content be no more than 100 ppm.

Engineering Standard ES-015 identifies that after years of RCS insulation installation and plant operation resulting in gradually increased containment heat load, a replacement program for the original mineral wool insulation was initiated. At that time, an engineering evaluation was performed and the decision was made to use fiberglass insulation in place of the mineral wool. BGE Drawing 83240 was created at the onset of this program to provide a controlled document that maintained an as-built status of all insulation installed in both CCNPP units. This drawing indicates, for RCS piping, where the original insulation is still installed as well as where the replacement fiberglass insulation has been installed.

ES-015 identifies three critical design characteristics for insulation on safety-related piping. They are the insulation thermal conductivity, the insulation density (for weight considerations), and the insulation corrosivity. It further identifies that insulation materials used at CCNPP, per design specifications, are to have less than 200 ppm leachable chlorides to control the possibility of insulation-caused SCC. It also further identifies that the addition of leachable inhibitors (usually sodium and silicon) within insulation materials can further neutralize corrosive effects.

BGE Drawing 83240 contains all of the SS piping classes that are identified as being within the scope of license renewal in the RCS Aging Management Review Report. All of these piping classes are insulated and covered with stainless steel jackets.

TGSCC of the external surfaces of RCS piping is not plausible because the stainless steel jacket and limited chloride content of the insulation prevents exposure of the piping surfaces to the wetted chloride environment needed for TGSCC to occur.

Additionally, the hypothesis that a leak could cause the wetting of piping externals with chloride contaminated water resulting in TGSCC is an event-driven scenario, not an aging or aging management scenario. Any kind of leak that could cause such wetting in containment would be detected and corrective actions would be taken accordingly. It would be a short-term anomaly.

Further, after obtaining and performing detailed reviews of complete copies of the LERs from the list sent to CCNPP as examples of the occurrence of SCC within the industry, it was found that these events do not involve aging or aging management. They were event-driven scenarios of one form or another.

It is, therefore, BGE's conclusion, because of the CCNPP insulation design considerations and because only an event-driven scenario could result in the remote possibility of the wetting of RCS piping with chloride contaminated water, that TGSCC of the RCS piping is not plausible.

Regarding OI 3.2.3.3.1.1-2:

Concerning whether air pockets promoting SCC could exist in the Reactor Coolant System:
Complete venting of the RCS precludes the existence of air pockets that could promote SCC. The following venting operations are performed:

- The Pressurizer is vented IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- The Reactor vessel is vented IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- Steam Generator tube sweeps are performed IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- Reactor Coolant Pump Seals are vented IAW CCNPP Operating Instruction OI-1E, Reactor Coolant Pump Seal Venting Procedure
- The Regenerative Heat Exchanger is vented IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- The Hot Leg Sample Line is vented IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- The CEDM/RVLMS housings are vented IAW CCNPP Technical Procedure RV-25, CEDM Housing Venting.

Concerning whether uninsulated RCS piping might be susceptible to SCC:

CCNPP Engineering standards require that all piping with a normal operating (process) temperature above 160F be insulated and jacketed with stainless steel. All RCS piping within the scope of license renewal is required to be insulated by this criteria. The only portions of the RCS that would not be insulated are instrument lines that are normally 160F or colder. For SCC to occur, all the contributing factors must be present. If any one of these factors is not present, SCC will not occur. The instrument lines in question would not be susceptible to SCC because at least two of the factors are not present:

- There is not a plausible source of chloride contamination
- Since the lines are uninsulated, there is no enveloping material to support an aqueous environment.

In addition, a third factor is not expected to be present:

- The temperature on the OD of the instrument lines should be below the threshold for SCC (150F). The instrument lines are dead-headed and the temperature of the OD will approach Containment ambient temperature.

Dave,
The information that remains would also be arranged more smoothly.

BGE will include RCS small bore fittings and branch connections in the ARDI program, for detecting cracking mechnisms. This program will examine representative components to determine if they will be capable of performing their intended function under all CLB design loading conditions during the period of extended operation. These examinations will be performed prior to the period of extended operation. The ARDI Program is defined in the CCNPP IPA Methodology presented in Section 2.0 of the application.

The elements of the ARDI Program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of adverse examination findings, including consideration of all design loadings required by the CLB and specification of required corrective actions; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Action Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

These inspections will be performed prior to, and near, the end of the current license period (e.g. no sooner than five years prior to the expiration of the current license) for each unit.

Regarding the pressurizer:

The highest fatigue locations are at the surge nozzle at the inside radius and at the safe-end transition. The design CUF is approximately 0.75. The next highest location internal to the pressurizer is the spray nozzle, with an approximate CUF of .07.

Section XI inspection category BD requires a volumetric examination of all full penetration nozzles once every 10 years. The inspection volume would include the highest fatigue locations in the surge nozzle. The volumetric exam is capable of detecting a flaw which has penetrated the cladding and propagated into the base metal.

Regarding the reactor vessel flange leak detection line:

These lines were downgraded from RCS pressure boundary to B31.7 Class II based on the existence of an orifice in the RV flange that limits flow rate from a break in the line to less than normal RCS makeup capacity.

These lines are not accessible in the areas of note. They are completely within the reactor vessel annulus region, which is below the permanent pool seal/shield. In order to perform a visual examination of these lines would require high radiation area entries.

Regarding RCS small bore piping:

BGE will include RCS small bore fittings and branch connections in the ARDI program, for detecting cracking mechnisms. This program will examine representative components to determine if they will be capable of performing their intended function under all CLB design loading conditions during the period of extended operation. These examinations will be performed prior to the period of extended operation. The ARDI Program is defined in the CCNPP IPA Methodology presented in Section 2.0 of the application.

The elements of the ARDI Program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of adverse examination findings, including consideration of all design loadings required by the CLB and specification of required corrective actions; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Action Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.

Regarding Small Bore RCS Piping (OI-3.2.3.2.1-4)

BGE participates in EPRI's Materials Reliability Program (MRP) Issue Task Group (ITG) on Thermal Fatigue, which is currently working on this issue. BGE will implement the eventual recommended actions from that EPRI effort, as appropriate, or, as a firm alternative, will include the RCS small bore piping in the Age Related Degradation Inspection (ARDI) Program.

Regarding CEA Shrouds:

Reference (a) addressed 24 requests for additional information on the Calvert Cliffs Reactor Vessel Internals System (RVI), a few of which involved RVI device type CEASB (CEA shroud and bolts). Reference (b) forwarded NRC's Safety Evaluation Report (SER) on BGE's License Renewal Application and contained Confirmatory Item 3.2.3.2.1-4, which also involved the CEASB. Reference (c) provided BGE's response to SER Open and Confirmatory Items (OIs and CIs), including the response to Confirmatory Item 3.2.3.2.1-4. Reference (d) requested further BGE interactions with NRC Staff on certain OIs and CIs, including Confirmatory Item 3.2.3.2.1-4. Those interactions have caused BGE to continue to assess our integrated plant assessment results for the CEASB. The results of that continued assessment are provided below and represent replacement of the response to Confirmatory Item 3.2.3.2.1-4 contained in Reference (c).

CEA Shroud and FAP Functions:

The CEA Shrouds and Fuel Alignment Plate (FAP) are part of the Reactor Vessel Internals (RVI) and contribute to the RVI functions as discussed in UFSAR Section 3.2.3.4.

> *The reactor internals are designed to perform their functions safely during steady state conditions and DBEs. The internals can safely withstand the forces due to deadweight, handling, system pressure, flow-induced pressure drop, flow impingement, temperature differential, shock, and vibration. The structural components satisfy stress values given in the ASME B&PV Code, Section III.*
>
> *The following limitation on stresses or deformations are employed to ensure capability of a safe and orderly shutdown in the combined event of earthquake and major loss-of-coolant accident (LOCA). For reactor vessel internal structures, the stress criteria are given in Table 3.2-1 of the UFSAR. The intent of the limits in this table is as follows:*
>
> *a. Under design loading plus design earthquake forces the critical reactor vessel internal structures are designed within the stress criteria established in ASME B&PV Code, Section III, Article 4;*
> *b. Under normal operating loadings plus maximum hypothetical earthquake forces, the design criteria permits a small amount of local yielding;*
> *c. Under normal operating loading plus reactor coolant pipe rupture loadings plus maximum hypothetical earthquake forces, permanent deformation is permitted by the design criteria.*
>
> *To properly perform their functions, the critical reactor internal structures are designed to satisfy the additional deflection limits described below, in addition to the stress limits given in Table 3.2-1 of the UFSAR.*
>
> *Und normal design loadings plus design earthquake forces or normal operating loadings plus maximum hypothetical earthquake forces, deflections are limited so that the CEAs can function and adequate core cooling is maintained. Under normal operating loadings plus maximum hypothetical earthquake forces plus pipe rupture loadings, the deflection design criteria depend on the size of the piping break. If the equivalent diameter of the pipe break is no larger than the largest line connected to the main reactor coolant lines, deflections are limited so that the core is held in place, the CEAs function normally, and adequate core cooling is maintained. Those deflections which would influence CEA movement are limited to less than two-thirds of the deflection required to prevent CEA function. For pipe breaks larger than the above, the criteria*

are that the fuel is held in place in a manner permitting core cooling and that adequate coolant flow passages are maintained. For these major pipe break sizes, CEA insertability is not required to achieve shutdown because the rapid voiding during the ensuing blowdown and the subsequent refill with the borated safety injection water ensures adequate shutdown margin for the reactor. For the larger break sizes, critical components are restrained from buckling by further limiting the stress levels to two-thirds of the stress level calculated to produce buckling.

The Upper Guide Structure (UGS) Assembly consists of the UGS Support Plate Assembly, CEA Shroud Assemblies, and the Fuel Assembly Alignment Plate (FAP). The UGS Assembly aligns and laterally supports the upper end of the fuel assemblies, maintains CEA spacing, supports the fuel assemblies during operation, prevents the fuel assemblies from being lifted out of position during severe accidents, protects the CEAs from the effect of reactor coolant cross flow in the upper plenum and supports the top-entry In-Core instrumentation. There are twenty dual and forty-five single CEA Shrouds. The CEA Shrouds extend from the FAP to an elevation above the UGS Support Plate. The FAP is designed to support and align both the upper ends of the fuel assemblies and the lower end of the CEA Shrouds. The FAP also has four equally spaced slots in the outer edge that engage with Stellite hardfaced lugs protruding from the core shroud to limit lateral motion of the UGS Assembly.

At the lower end of each CEA Shroud, flow channels protrude approximately 2.25 inches into a precision-machined 6.810-in. diameter hole in the 3-inch-thick FAP. This serves as an alignment feature between the CEA Shroud and the FAP. Radial clearances are 0.016 inches and 0.021 inches for single and dual Shrouds respectively. In order that the FAP may be removed with the UGS for refueling and to prevent relative movement between the FAP and the CEA Shroud, the CEA Shrouds are attached to the FAP by threaded structural fasteners (bolts). The bolts are installed through the under side of the FAP and thread into the CEA Shrouds.

The cross sectional area of the flow channel protrusion into the FAP is slightly less than the cross sectional area of the bolts that connect the FAP to the CEA Shroud. The bolts are preloaded thus imparting a vertical compressive force at the interface between the bottom surface of the CEA Shroud and the upper surface of the FAP. There are 8 bolts for each single CEA Shroud and sixteen for each Dual CEA Shroud. The bolts are captured in place by means of a counter bore in the FAP and a lock bar that engages with precision-machined castellated slots in the head of the bolts. The lock bar is welded to the FAP; no welding is permitted on the 7/8-inch diameter bolts.

Normal Operation: During Normal Operation the Fuel Assembly Hold Down Springs and the hydraulic loads provide vertical upward forces on the FAP that are directly transmitted to the CEA Shrouds and serve to force the FAP against the CEA Shrouds. The CEA Shrouds have horizontal hydraulic forces imposed on them from the reactor coolant cross flow that is exiting from the UGS plenum to the Reactor Vessel outlet nozzles. Lateral displacement of the lower end of the CEA Shroud is prevented by the tight radial clearances discussed above, by the frictional forces resulting from the upward flow and fuel assembly spring forces pressing the FAP against the CEA Shrouds.

Upset and Faulted Conditions: When considering both seismic and LOCA, the vertical load application to the FAP is consistent with Normal Operation in the respect that the FAP is contained between the bottom surface of the CEA Shrouds and the top of the Fuel Assemblies. The FAP upward forces are transmitted directly to the CEA Shrouds with no additional load on the bolts. The vertical downward forces on the FAP are resisted by the bolts and the fuel assembly holdown springs. The horizontal forces imposed on the FAP are reacted by the CEA Shrouds through the preloaded connection and the flow channel protrusions. In the absence of any bolts, the protrusion of the CEA Shroud flow channels into the FAP react the horizontal forces. The UGS, CEA Shrouds, and FAP would retain their design functions under all design basis loads.

Therefore the CEA Shroud bolts are not required for the CEA Shroud and FAP functions to be performed during normal and DBE conditions.

Potential for Wear between the FAP and CEA Shroud flow channels

The radial clearance between the FAP and CEA Shroud flow channel protrusions would need to increase significantly (e.g., greater than 0.5 inch from the original 0.016 inch) for CEA Shroud alignment and CEA insertion functions to be affected during normal operating or accident conditions. This could only occur as a result of excessive wear and could only occur if the clamping force holding the FAP against the CEA Shrouds were insufficient to prevent lateral relative movement. Such movement would need to be oscillatory in nature for wear to occur.

Normal Operation: In the unlikely absence of any intact CEA Shroud bolts, the lateral flow force on a CEA shroud during normal operation is not sufficient to overcome the friction forces between the FAP and the CEA shroud or result in excessive oscillatory movement. Therefore, wear cannot occur during normal operation.

Upset and Faulted Conditions: Wear during DBEs is not a concern since these are one-time events.

Conclusions

An aging effect is considered plausible for a specific component if, when allowed to continue without any prevention or mitigation measures or enhanced monitoring techniques, it could not be shown that the component would maintain its capability to perform its intended, passive function throughout the period of extended operation. The underlying function of concern in this instance is maintaining the alignment between the FAP and CEA Shrouds so that CEAs function as required and core cooling is maintained.

Because of the tight radial clearances between the CEA Shroud flow channels and the precision machined holes in the FAP, BGE has determined that the conditions needed for unacceptable wear to occur at the interface between the FAP and CEA Shrouds are not credible. The CEA Shrouds and FAP will resist vertical and lateral operating and accident loads to the extent necessary for the CEAs to function as required and for adequate core cooling to be maintained.

Regarding CASS questions passed to BGE via telephone on 9/7/99:

<u>Question 1</u>: Provide the basis for the cut off of the 15 KSI Tensile Stress for plausibility of thermal aging in reactor vessel components. This should be identified as a cut off in the significance of the impact of thermal aging, not plausibility of the ARDM.

Response: This question is about the core support columns. The answer, and the 15 ksi screening load, are applicable only to the core support columns.

Evaluation of the effects of thermal aging of CASS can be complicated if the affected component is also subjected to neutron fluence. Thermal aging and neutron embrittlement of CASS are postulated to potential create a reduction in the component material's fracture toughness. For those few components subject to both thermal and neutron embrittlement, it has not been possible to develop a program to screen for plausibility. Instead, reduced toughness is assumed, and the effects of the reduction are to be evaluated.

Any effect of reduced toughness is manifested as a higher likelihood of flaw growth in a structure subjected to a particular tensile load.

The function of the core support column is to transmit much of the weight of the core to the core support barrel. The remainder of the weight is transmitted through an annular skirt. The function of transmitting weight creates predominantly compressive stress. For all operational condition the average loading on the core support columns is significantly compressive.

There are portions of the core support columns, however, that may experience some nominal tensile stress under certain operational conditions. Specifically, for some operational events it is expected that the batwing shaped fingers at the top of the columns may experience tensile stresses.

In order to evaluate the effects of embrittlement of the core support columns, it is most efficient to evaluate whether significant tensile loading occurs. For most of the surface and volume of the columns the stresses are always compressive. For screening purposes it was proposed to determine the highest loaded location under the most severe service and accident conditions and make sure the highest tensile load was reasonably low. The selection of 15 ksi as a reasonably low tensile stress was somewhat arbitrary, but represents approximately one-half the yield strength of the material.

<u>Question 2</u>: Provide a description of the plans for susceptible piping, base metal - inspect, replace, or what? Regarding the surge line, are there any activities related to NRC Bulletin 88-11 that effectively serve as aging management for the surge line?

Response: Components which do not meet the screening criteria described in reference 1 will be:

1. Subject to an augmented inspection combined with a flaw tolerance evaluation, or,
2. A full leak-before-break evaluation will be performed to prove that current inspection requirements are adequate to prevent catastrophic failure, or,
3. Replaced.

Components subject to augmented inspection will be inspected as if they were pressure retaining welds in ASME Section XI category B-L-1, B-M-1, or BJ components. Generally, this will be a volumetric examination. If available inspection technology does not permit a volumetric examination, an alternative approach similar to that described in Code Case N-481 will be used to manage thermal aging embrittlement of the component.

A flaw tolerance evaluation will be performed to determine required inspection sensitivity for non-destructive examination, and to determine the disposition of detected flaws. The flaw tolerance evaluation will be conducted in accordance with ASME Section XI, 1989 edition, article IWB-3640, or an equivalent procedure if a later code edition is used. The allowable end-of-evaluation period flaw sizes will be determined as follows:

- If the limit load can be achieved prior to unstable flaw propagation per IWB-3641 (c), allowable flaw sizes for GAW, GMAW, or base metal will be used
- If limit load cannot be achieved prior to unstable flaw propagation, allowable flaw size standards for SAW and SMAW welds will be used.

The J-R toughness curves used in these evaluations will be estimated using the method of Reference 2 or equivalent. In extreme cases where the allowable flaw size is too small to detect with available technology, components will be replaced. However, such results are not expected.

Regarding the surge line, activities related to NRC Bulletin 88-11 may effectively serve as aging management for the surge line. BGE is currently awaiting ASME development of guidance for inspecting such piping for thermal fatigue. Once ASME guidance is provided BGE intends to determine the extent of inspections to be conducted.

Question 3: Confirm the presence/absence of CASS valves (that includes - bodies & bonnets) in the RCS, since the LRA is ambiguous on this item.

Response: The RCS includes valves with CASS bodies and bonnets. With few exceptions, these valves are vent, drain, and instrument isolation valves that are not subject to RCS flow and are configured (distance and geometry) so that they are not regularly subjected to temperatures exceeding 500F. Although not clearly stated in the LRA, CASS valves (bodies & bonnets) in the RCS are subject to the CASS evaluations.

Question 4: Provide the basis for not requiring inspection of niobium containing CASS parts except for reactor vessel internals.

Response: BGE did not intend to exclude niobium containing RCS CASS parts from inspection. It should be noted that BGE review of material specifications and certifications has not identified any components for which niobium was intentionally added.

References

1. Letter from Mr. C. H. Cruse to NRC dated July 2, 1999, re: Calvert Cliffs Nuclear Power Plant Unit Nos. 1 & ; Docket Nos. 50-317 & 50-318 Response to License Renewal Safety Evaluation Report

2. Chopra, O. K., Shack, W. J., "Assessment of Thermal Aging Embrittlement of Cast Stainless Steels", NUREG/CR-6177, ANL-94/2, May 1994

Regarding OI 3.2.3.3.1.1-2:

Concerning whether air pockets promoting SCC could exist in the Reactor Coolant System: Complete venting of the RCS precludes the existence of air pockets that could promote SCC. The following venting operations are performed:

- The Pressurizer is vented IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- The Reactor vessel is vented IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- Steam Generator tube sweeps are performed IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- Reactor Coolant Pump Seals are vented IAW CCNPP Operating Instruction OI-1E, Reactor Coolant Pump Seal Venting Procedure
- The Regenerative Heat Exchanger is vented IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- The Hot Leg Sample Line is vented IAW CCNPP Operating Procedure OP-7, Shutdown Operations.
- The CEDM/RVLMS housings are vented IAW CCNPP Technical Procedure RV-25, CEDM Housing Venting.

Concerning whether uninsulated RCS piping might be susceptible to SCC:

CCNPP Engineering standards require that all piping with a normal operating (process) temperature above 160F be insulated and jacketed with stainless steel. All RCS piping within the scope of license renewal is required to be insulated by this criteria. The only portions of the RCS that would not be insulated are instrument lines that are normally 160F or colder. For SCC to occur, all the contributing factors must be present. If any one of these factors is not present, SCC will not occur. The instrument lines in question would not be susceptible to SCC because at least two of the factors are not present:

- There is not a plausible source of chloride contamination
- Since the lines are uninsulated, there is no enveloping material to support an aqueous environment.

In addition, a third factor is not expected to be present:

- The temperature on the OD of the instrument lines should be below the threshold for SCC (150F). The instrument lines are dead-headed and the temperature of the OD will approach Containment ambient temperature.

Proposed Response:

BGE has compared the CVCS and RCS components applicable to this issue. The table below provides a summary of the comparison.

	CVCS	RCS
Material	ASTM A-376 or A-312, Type 304 SS	ASTM A-376 or A-312, Type 304 or Type 316 SS
Design Code/Class	B31.1	B31.7, Class I or II
Pipe Sizes	4 inch and under	4 inch and under
Internal Environment	Concentrated Boric Acid Solution (No Hydrogen Over-Pressure)	RCS Water Chemistry (Hydrogen Over-Pressure)
Service Conditions	1. Boric Acid Pump Suction: 5 psig, 165° F 2. Boric Acid Pump Discharge: 110 psig, 165° F	1. Letdown Flow to Containment Isolation Valve: 2235 psig, 550° F 2. Isolation Valves downstream of RHX to RCS: 2235 psig, 450° F 3. RCS Auxiliary Piping: 2235 psig, 604° F 4. RCS Drains and Vents: 2235 psig, 604/550° F 5. Pressurizer Safety and Relief Valve Piping: 2235 psig, 653° F 6. Pressurizer Spray System: 2235 psig, 550° F 7. Downstream PZR Safety and Relief Valve Piping: 300 psig, 653° F

The material and fabrication requirements for the components in both systems were identical with respect to the factors that influence susceptability to age related degradation mechanisms, such as stress corrosion cracking.

- The piping materials used to construct the CVCS and RCS small-bore piping are susceptible to SCC when exposed to chloride-containing solutions at temperatures in excess of 150°F.

- Type 304 and type 316 stainless steel have similar susceptibility to SCC when exposed to chlorides.

- Sensitization of austenitic stainless steels such as type 304 or type 316 can increase the susceptibility to SCC and allow SCC at lower chloride concentrations, particularly as dissolved oxygen increases. Sensitized areas would only exist in the heat-affected zone (HAZ) of welds. The same group of weld procedures were used in the fabrication of both systems. The fabrication specification for both systems required a 350°F maximum interpass temperature. An interpass limit temperature is generally specified to limit the amount of time the base material can be exposed to temperatures which produce sensitization (800-1200°F). Therefore, a similar potential for SCC due to sensitization exists in both the CVCS and RCS small bore piping when exposed to a condusive environment.

A higher assurance level due to more rigorous inspection and testing requirements for RCS ensures the fabrication of the RCS small bore piping is equal to or better than the CVCS from a quality standpoint. Therefore, in terms of the probability of degradation due to fabrication irregularities, the CVCS bounds the RCS.

BGE maintains the conclusion that the ARDI to be performed on the CVCS System small bore piping will bound the small bore piping in the RCS.

previous proposed response:

BGE discussed operating experience with the Reactor Pressure Vessel Head Closure Seal Leakage Detection Lines on pages 4.1-8 and 4.1-46 of the BGE LRA. The Unit 2 line had cracked, due to an ever increasing concentration of contaminants in the vicinity of the cracking due to repeated boil off of the liquid left in the line at the end of each refueling, eventually reaching levels high enough to cause TGSCC. The lines in both Units were subsequently replaced. Measures were taken to prevent recurrence in that the lines were to be drained and blown dry every refueling outage. The practice of blowing the lines dry changed this aging scenario entirely.

The BGE LRA characterized this scenario as plausible aging with a mitigative program (blowing the lines dry). Because that program actually eliminates the cause of the experienced cracking, no cracking is expected. Therefore no discovery program was deemed necessary and none was identified in the LRA.

NRC staff subsequently requested an additional program (presumably a discovery program), saying that the proposed program was merely mitigative. BGE believes no purpose would be served by a discovery program, based on the reasoning given above. BGE also believes that because the aging scenario was changed entirely by the practice of blowing the lines dry, we should have characterized this scenario as having no aging effects plausible, with a BGE commitment to continuing the practice of blowing the lines dry during each refueling outage.

The key factor involved here is that, through operating experience and our corrective action program, we not only took corrective action, but action to prevent recurrence. The operating experience with cracking is therefore related to a scenario that no longer exists.

Additional information sent after 9/21/99 teleconference:

attached items

- RCAR 9506 (14 pages, including drawings 1 thru 5)
- Not-to-scale drawing of "Reactor Vessel No. 11 Leakange Monitor Tube" (1 page)
- Unit 1 and Unit 2 drawings of leak off line (isometric) (3 pages)
- Page 12 of 25 from procedure RV-78 (1 page)

Additional information:

- Although the areas of the detector (on one end) and the reactor vessel flange (on the other end) are somewhat accessible, when the vessel head is removed, the majority of the lines are not accessible for visual inspection.
- The geometries are such that on Unit 2 elevations are lower and lower from the vessel flange to the other end of the line, but on Unit 1 the half inch tubing was dropped $4 \pm .5$ inches before it runs nearly half way around the vessel, then brought up that same $4 \pm .5$ inches just before it transitions to ¾ inch pipe.
- At the detector end, the line branch to the detector and to a blank flange, each with two isolation valves. No other valves exist in the lines.
- The root cause analysis report discusses the NDE that was performed and shows the crack locations.
- The steps on page 12 from procedure RV-78 demonstrate that the line is blown from the vessel flange hole to the blank flange on the other end.

TO: C.H. Cruse 5/5/95

Plant General Manager

Root

Cause

Analysis

Report

Nuclear Unit	Event Date/time	Report No.	Priority	Evaluators
Calvert Cliffs - 1 & 2	1/13/94 3:30am	RCAR 9506	2	E.C. Flick ECF 5/3/95 C.J. Dobry CJD 5/3/95

EVENT SUMMARY

On January 13, 1994, while Unit 2 was in mode 3 during a forced outage, an active Reactor Coolant System (RCS) leak was identified on the Reactor Vessel o-ring leak detection pipe below the reactor flange. An Unusual Event was declared, because of Class I pressure boundary leakage. In accordance with Technical Specification 3.4.6.2(a), Unit 2 was shut down to Mode 5. The Unusual Event was terminated following approval of MCR 94-064-001 which down graded the pipe from Class I to Class II. Unit 2 was restarted following repair of the pipe.

SUMMARY OF ROOT CAUSE

Chloride Ion Stress Corrosion Cracking (CISCC) of the Reactor Vessel o-ring leak-off pipe was caused by elevated levels of chlorides in the pipe. The chlorides in Refueling Pool water trapped in the pipe following Reactor Vessel head installation can become concentrated on the inside of the pipe by boiling of the water during plant operation. The high chloride source may have been present inside of the pipe since initial plant construction.

SUMMARY OF RECOMMENDATIONS

All corrective actions and recommendations have been implemented; no additional actions are necessary. The following is a list of actions taken.

Pipe stress calculations and nozzle loading studies were reviewed. Pipe stresses and nozzle loadings were found to be acceptable for Units 1 and 2.

The Reactor Vessel o-ring leak-off piping for Unit 1 and 2 were replaced. Pipe and hanger installation was verified to be according to design.

Maintenance procedure RV-78 (Reactor Vessel Closure Head Installation) was modified to require draining the leak detection piping and drying it with compressed air after the Refueling Pool is drained.

EVENT NARRATIVE

During a Unit 2 containment walkdown on January 13, 1994 at 3:30am with the Unit in mode 3, boric acid crystals and an active RCS leak were found on the reactor o-ring leak detection piping to 2-PIA-118. The boric acid crystals were removed from the pipe and two through wall pinhole leaks were found. It was determined that the Reactor Vessel inner o-ring was leaking and that the reactor coolant was in turn leaking out of the pipe. Plant Operations entered the Action Statement for Technical Specification 3.4.6.2(a) and 3.4.10.1(a) at 4:30am because the leakage was RCS pressure boundary leakage and the integrity of Class 1 piping was not being met. Unusual Event 3760 was declared at 9:30am because of the Class 1 pressure boundary leakage and the unit was shut down to mode 5 in accordance with Technical

Specification 3.4.6.2(a). Following approval of MCR 94-064-001 (downgrade the pipe to Class II) the Unusual Event was terminated. The failed section of piping was replaced by January 15, 1994. Unit 2 was restored to mode 1 operation on January 19, 1994.

INVESTIGATION

Failure of the inner Reactor Vessel o-ring is being evaluated separately by RCAR 9507 (PDR 94009).

Following discovery of the Unit 2 leak, the Nondestructive Evaluation Unit (NDEU) performed a dye penetrant examination of the suspected leak area. A 3 inch section of pipe is welded to the Reactor Vessel flange penetration, an elbow is welded to this section, and a long section of pipe is welded to the elbow. NDEU found numerous indications, both axial and circumfrential, in the 14 inch span of pipe immediately downstream of the elbow (see Drawings 1 and 2). No indications were found outside of this span.

The Materials Testing and Evaluation Unit (MTEU) performed a metallographic examination of the cracked section of pipe after the pipe was cut out of the system (MO# 2199400148 and 2199400106). Numerous through wall cracks oriented axially and circumfrentially were noted; the cracks propagated from inside to outside of the pipe. MTEU determined that the pipe had cracked by Trans Granular Stress Corrosion Cracking (TGSCC). The microstructure inside the pipe appeared to be heavily cold worked (cold work can make stainless steel more susceptible to TGSCC).

Plant Design Support Unit (PDSU) reviewed the Reactor Vessel o-ring piping calculations and nozzle loading studies for Unit 1 and 2. PDSU determined that the pipe stresses were greater in Unit 1 than Unit 2, but were within Code allowable limits. The different stresses between Unit 1 and 2 are due to pipe routing differences, and pipe thickness (Unit 1 is schedule 80 pipe and Unit 2 is schedule 160 pipe). No design changes were needed based on the review since the pipe stresses were within acceptable limits.

MTEU observed a black deposit on the inner diameter of the removed section of pipe. Plant chemistry performed a chloride analysis on a sample of DI water flushed through a section of the pipe. Some of the deposit was washed out when the pipe was flushed. The pipe section measured approximately 30 inches in length, and was located immediately downstream of the cracked area. Chemistry measured a chloride concentration of 950 parts per billion in the flush water. The volume of water flushed through the line was 210 milliliters, slightly larger than the volume of the 30 inch section of pipe. Assuming all chloride in the pipe section was dissolved by the flush, the actual chloride content in the line if it was completely full was approximately 1.3 parts per million. The flush probably did not dissolve all the chloride present in the pipe section so the concentration in the line may have been significantly higher than 1.3 part per million. MTEU concluded that the cracking was caused by the chloride contaminant inside of the line combined with sufficient temperature and stress. This specific type of cracking is called Chloride Ion Stress Corrosion Cracking (CISCC). CISCC can occur in stainless steel when concentration of chloride is greater than 100 parts per billion.

Primary Systems Engineering Unit (PSEU), MTEU, and PDSU reviewed system drawings and maintenance practices to determine where the chlorides could have come from. This pipe was determined to be a unique dead leg off of the RCS; normally (when a inner reactor o-ring is not leaking), this pipe does not see system pressure, or exchange liquid with the RCS. The only times that the pipe could be filled with liquid or steam are during operation with a failed inner reactor o-ring, or during refueling (with the reactor head removed) when the pipe is open to the Refueling Pool. The pipe is not flushed or drained following a refueling outage when water could enter the pipe; no records could be found indicating that the pipe had ever been flushed (including during the initial hydrostatic test of the line) in the history of the plant. The following were determined to be possible sources for chloride being inside the pipe:

1) High levels of chloride were present in the pipe from initial construction.

2) Chlorides present in trapped Refueling Pool water become concentrated by boiling of the water during plant operation.

3) A chloride containing substance washed into the pipe during Reactor Vessel flange cleaning.

On January 15, 1994 it was determined that Unit 1's Reactor Vessel o-ring leak detection pipe could be susceptible to a similar cracking mechanism as Unit 2. While Unit 1 was shutdown during the week of January 24, 1994 a visual inspection of the leak detection piping revealed no signs of boric acid crystals on the pipe and pressure gauge 1-PIA-118 indicated zero pressure with the RCS at full pressure (this provided additional assurance that the inner Reactor Vessel o-ring was not leaking). An operability evaluation was approved to justify continued operation of Unit 1 until the 1994 Refueling Outage. Maintenance order 1199400378 was added to the 1994 Refueling Outage scope to replace the entire run of pipe and tube from the Reactor Vessel flange to instrument 1-PIA-118.

During the Unit 1 piping replacement (Spring 1994 Refueling Outage) it was discovered that the nozzle connection in the Reactor Vessel flange was cracked in addition to the same piece of pipe that was cracked on Unit 2 (see Drawings 3-5). MCR 94-084-001 was processed to re-route the leak detection piping and tubing to a penetration on the opposite side of the Reactor Vessel and plug the old leak detection port in the Reactor Vessel flange. An evaluation of the removed Unit 1 piping revealed through wall CISCC and a black deposit in the same locations as the Unit 2 piping.

At the end of the Unit 2 1995 Refueling Outage it was confirmed that the o-ring leak-off pipe fills with Refueling Pool water while the Refueling Pool is flooded. The pipe was opened (MO# 2199403972) after the Refueling Pool was drained; it is estimated that 1 gallon of water was drained from the pipe.

POSSIBLE CAUSES AND EVALUATION

1. **Thermal expansions and contractions of the Reactor Vessel during heat-up and cool-down induced high bending stresses in the leak-off line and caused the pipe to fatigue crack.**

   MTEU concluded that the cracking was caused by the chloride contaminant inside of the line (not a fatigue failure) combined with sufficient temperature and stress. PDSU reviewed the Reactor Vessel o-ring piping calculations and nozzle loading studies for Unit 1 and 2. PDSU determined that the pipe stresses were high, but were within Code allowable limits. This specific type of cracking is called Chloride Ion Stress Corrosion Cracking (CISCC).

2. **Chlorides were present on the outside of the pipe from poor work practices.**

   Analysis performed by MTEU and Plant Chemistry determined that the chlorides were on the inside of the pipe and that the cracking was initiated from inside to the outside of the pipe; this is therefore not a credible cause.

3. **A chloride containing substance washed into the pipe during Reactor Vessel flange cleaning.**

   A review of the maintenance procedures for cleaning the Reactor Vessel flange and interviews with people in organizations that perform the work did not reveal that anything other than Deionized Water or Bypass Solution (CML# 900-205) have been used to clean the flange; both of these are approved for use by Plant Chemistry. There is no evidence that the chloride containing substance was washed into the Unit 1 and 2 pipes during flange cleaning.

4. **High levels of chloride were present inside of the pipe from initial plant construction.**

This pipe was determined to be a unique dead leg off of the RCS; normally (when a inner reactor o-ring is not leaking), this pipe does not see system pressure, or exchange liquid with the RCS. The only times that the pipe could be filled with liquid or steam are during operation with a failed inner reactor o-ring, or during refueling (with the reactor head removed) when the pipe is open to the Refueling Pool. There is no motive force to cause water to flush in and out of the pipe during normal operation or during refueling. The pipe is not flushed or drained following a refueling outage when water could enter the pipe; no records could be found indicating that the pipe had ever been flushed (including during the initial hydrostatic test of the line) in the history of the plant.

The composition of the black deposit on the inside of the pipe could not be definitively identified although Plant Chemistry confirmed that it was a high chloride source. MTEU believes that the black deposit contains iron oxide (rust).

Since the black deposit was found in the pipe of Unit 1 and 2, and since the pipes are different wall thickness' (purchased, stored, and installed at different times), it is considered to be a low probability that both Units were fabricated with identically poor work practices or contaminated material. It is possible (but can not be confirmed) that the high chloride substance was present in the pipe since initial plant construction.

5. **Chlorides present in the trapped Refueling Pool water become concentrated by boiling of the water during plant operation.**

The Reactor Vessel is insulated; the o-ring leak-off pipe is not insulated. The failed section of piping was in a long run attached to the elbow just beyond the Reactor Vessel insulation. The temperature of RCS water on the inside of the Reactor Vessel at the elevation of the leak-off pipe penetration is between 548 and 595 °F; the temperature of the insulated vessel wall pipe nozzle is expected to be in the same temperature range. The air temperature outside of the Reactor Vessel, in the area of the uninsulated leak-off piping, is a maximum 170°F (Bechtel calculation sheet, job #9379, for cavity cooling temperatures).

Refueling Pool water in the pipe after the reactor head is installed is initially at atmospheric pressure. Increasing the RCS temperature causes the Reactor Vessel wall and the outlet nozzle for the o-ring leak detection pipe to heat-up. Water in the line heats up and boils at the Reactor Vessel end, creating a steam bubble. It was confirmed that this steam bubble occurs by a history search which determined that typically during heat-up following a refueling outage, pressure instrument PIA-118 will alarm in the control room until an operator vents off the pressure (typically this was performed several times until a steam bubble no longer occurred).

The cracking was only found in the uninsulated 14 inch span of pipe downstream of the elbow; this is the portion of pipe which is subject to the highest temperature gradient and bending stress. The pipe in the vicinity of the Reactor Vessel is the place where water can boil and chlorides can concentrate above the levels of a few parts per billion normally present in RFP water. Locally elevated chloride levels combined with the higher temperature and stress in this section of pipe would cause CISCC.

A review of plant procedures and design documents did not reveal any requirements to drain Refueling Pool water out of the o-ring leak-off line before installing the Reactor Vessel head.

Because this cracking mechanism is unique to this pipe configuration, it is unlikely that it was considered during initial plant design.

VERIFICATION OF ROOT CAUSE

The failed section of leak-off pipe that was removed from Unit 1 and 2 was subjected to metallographic examinations by the MTEU. Axial and circumfrential through wall cracks were identified. Non-through wall cracks on the inside of the pipe were also found indicating the cracks were initiated from the inside of the pipe. MTEU observed a black substance on the interior of the pipe during their examination , the pipe was flushed with DI water and some of the black substance dislodged and became suspended in the water. The flushed water was analyzed and was found to contain 950 parts per billion chloride. Type 316 stainless steel under tensile stress is susceptible to ClSCC in solutions containing chlorides. Chloride levels as low as 100 parts per billion can cause ClSCC of type 316 stainless steel, typically at temperatures between 140 and 250°F. The o-ring leak-off piping (from the Reactor Vessel nozzle to the pipe in the reactor annulus) is subject to a temperature gradient from about 548 °F to 170 °F. Based on these findings, the failure mechanism was identified as ClSCC.

It is possible (but can not be confirmed) that the high chloride substance was present in the pipe since initial plant construction. The composition of the black deposit on the inside of the pipe could not be definitively identified although Plant Chemistry confirmed that it was a high chloride source. MTEU believes that the black deposit contains iron oxide (rust). The black deposit was found in the pipe of Unit 1 and 2. A review of maintenance practices indicates that rust deposits from the Reactor Vessel flange could become trapped in the pipe when the Reactor Vessel flange is cleaned prior to installing the reactor head. The deposit could also be from iron oxide dissolved in RCS water which enters the pipe during refueling.

At the end of the 1995 Refueling Outage it was confirmed that the pipe fills with Refueling Pool water by opening the line after the Refueling Pool was drained; it is estimated that 1 gallon of water was drained from the pipe.

Water trapped in the pipe during operation would heat up and boil at the Reactor Vessel end, creating a steam bubble. This was confirmed by a history search (described above). The section of pipe where the water boils is where chlorides and other impurities (such as dissolved iron oxide) will concentrate above the levels normally present in RFP water. It is not cost beneficial or necessary to perform mock-up testing to confirm that boiling water will concentrate impurities; the following are examples of boiling water concentrating impurities: ICI flanges leaking RCS water concentrated boric acid and other impurities on the flanges, boiling a pot of water with salt or other substance in it will concentrate a ring of impurities above the water surface on the pot.

SAFETY IMPLICATIONS

ACTUAL SAFETY CONSEQUENCES

There were no actual safety consequences associated with this event. Upon discovery of the cracked pipe, Unit 2 was shutdown to mode 5 in accordance with Technical Specification .6.2(a) without incident. The Compliance Unit determined that this event was not reportable under 10CFR50.73.

POTENTIAL SAFETY CONSEQUENCES

Any leakage out of the pipe predisposes that the inner Reactor Vessel o-ring is leaking. o-ring leakage is considered to be unidentified leakage per Technical Specification 3.4.6.2; the leak rate was very conservatively estimated to have been 0.4 gpm; the leakage did not challenge the 1.0 gpm unidentified leak rate shutdown limit.

Catastrophic failure of the leak-off line piping resulting from CISCC is not a plausible mechanism by which type 316 stainless steel fails. Type 316 stainless is extremely tough and ductile and does not fail in a brittle manner above -200°F. It was determined that the cracked pipe was not actually Class I, but was really Class II. In the unlikely event the leak-off pipe were to break off and the inner o-ring was completely failed during reactor operation, the maximum leakage out of this cracked pipe would be limited to less than the make-up capacity of the charging pumps (as allowed by 10CFR50.55a) by the 3/16" orifice at the Reactor Vessel flange. The leakage would be bounded by the small break LOCA analysis.

If the pipe were cracked during refueling operations, Refueling Pool water could be lost. Leakage would be identifiable by constantly increasing Containment sump level and by lowering water level in the Refueling Pool. The rate of leakage is bounded by the analysis for failure of the old style rubber Refueling Pool seal (The leak area assumed in the pool seal failure is 0.27 square feet. The leakage area for the cracked pipe restricted by the 3/16" orifice is 0.00019 square feet). AOP-6E (Loss of Refueling Pool Level) would dictate the mitigating actions to be taken.

GENERIC IMPLICATIONS

Both Unit 1 and Unit 2 experienced CISCC of this pipe in the same location. Several factors have to occur simultaneously for CISCC to occur, these being chloride in concentrations above 100 ppb, temperature between 140 and 250°F and piping stresses. This pipe was determined to be a unique dead leg off of the RCS; normally (when a inner reactor o-ring is not leaking), this pipe does not see system pressure, or exchange liquid with the RCS. The only times that the pipe could be filled with liquid or steam are during operation with a failed inner reactor o-ring, or during refueling (with the reactor head removed) when the pipe is open to the Refueling Pool. A review of stainless steel plant piping and tubing (with process fluid temperatures in excess of 150°F) did not find any similar configurations that would either concentrate chlorides or remain unflushed since initial plant construction leading to CISCC.

SIMILAR EVENTS

Calvert Cliffs Events

The stainless steel 21 Refueling Water Tank (RWT) was found to have cracked by CISCC during the 1993 Refueling Outage. The chloride source was not positively identified, but may have been from a worker perspiring on the weld during fabrication. The crack initiated from outside to inside.

The stainless steel Reactor Vessel head vent line was found to be cracked from CISCC at the end of the 1994 Refueling Outage. This cracking initiated from outside to inside. The cause was attributed to maintenance practices which allowed a chloride contaminant (such as tape or perspiration) on the outside of the pipe.

The cement for the heat tracing for the Boric Acid Storage Tank process piping has been found to contain high levels of chlorides. Several instances of CISCC has occurred in the stainless steel pipe. The cracks initiated from outside to inside.

Industry Events

OE 3088 identifies CISCC cracks in 33 control rod drive insertion line pipes at the Duane Arnold Energy Center on 11/20/88. The high chloride source was traced to decomposed electrical cabling insulation. The cabling was adversely affected by high temperature; the decomposed cable jacketing allowed chlorides to leach into the pipe causing CISCC. The cracks initiated from the outside of the pipe.

OE 3295 and 3290 identify that Turkey Point 3 experienced CISCC of 50 stainless steel thimble guide tubes for their in-core-instruments on 4/1/89. The high chloride source was on the outside of the thimble guide tubes.

OE 3387 notes that Connecticut Yankee experienced a failure of their circulating water pump shaft on 9/27/88. The cause was identified as CISCC of stainless steel cap screws in the pump coupling. The coupling was periodically exposed to Connecticut River water and hypochlorite treatments.

OE 4354 discusses a CISCC failure of two CEDM housings on 12/14/90 at Fort Calhoun 1. The cracks were found in the vicinity of a weld overlay on the inside of the housings. High oxygen levels (from not venting CEDM housings) combined with low chloride levels (within technical specification limits) and the heat effected zone of the weld overlay caused CISCC of the stainless steel pressure housings. The cracking was initiated on the inside of the housing. This event was evaluated at Calvert Cliffs and corrective actions were taken as noted in POEAC OI 91-02-04.

CORRECTIVE ACTIONS

These corrective actions address both CISCC of the Reactor Vessel o-ring leak-off pipes and the potential sources of the chlorides. All corrective actions and recommendations have been implemented; no additional actions are necessary. The following is a list of actions taken.

- **Pipe stress calculations and nozzle loading studies were reviewed. Pipe stresses and nozzle loadings were found to be acceptable for Units 1 and 2. (AIT# 1P9400009 milestones 001, 002, 007)**

  The pipe stress calculations and nozzle loading studies were reviewed because it was necessary to determine that the pipe was not subject to excessive stress during thermal expansion and contraction of the Reactor Vessel. These reviews also eliminated the possibility that the pipes cracked because of fatigue. Since the pipe stresses were found to be acceptable, no design changes were necessary.

- **The Reactor Vessel o-ring leak-off piping for Unit 1 and 2 were replaced. Pipe and hanger installation was verified to be according to design. (MO# 1199400378 and 2199400984)**

  The piping for Unit 1 and 2 was found to be have a chloride contaminant in it. The Unit 1 and 2 piping was replaced and cleaned to insure that there was no chloride contamination.

  The pipe and hanger installation was verified to be according to design to insure that the pipe stresses were not in excess of the design.

- **Maintenance procedure RV-78 (Reactor Vessel Closure Head Installation) was modified to require draining the leak detection piping and drying it with compressed air after the Refueling Pool is drained (Change Report 94-191 for RV-78).**

Modifying procedure RV-78 to drain and dry the pipe after refueling will insure the following:

Contaminants such as rust will be flushed out of the pipe after each reactor refueling.

There will not be a source of refueling water to concentrate contaminants (such as chlorides) in the pipe.

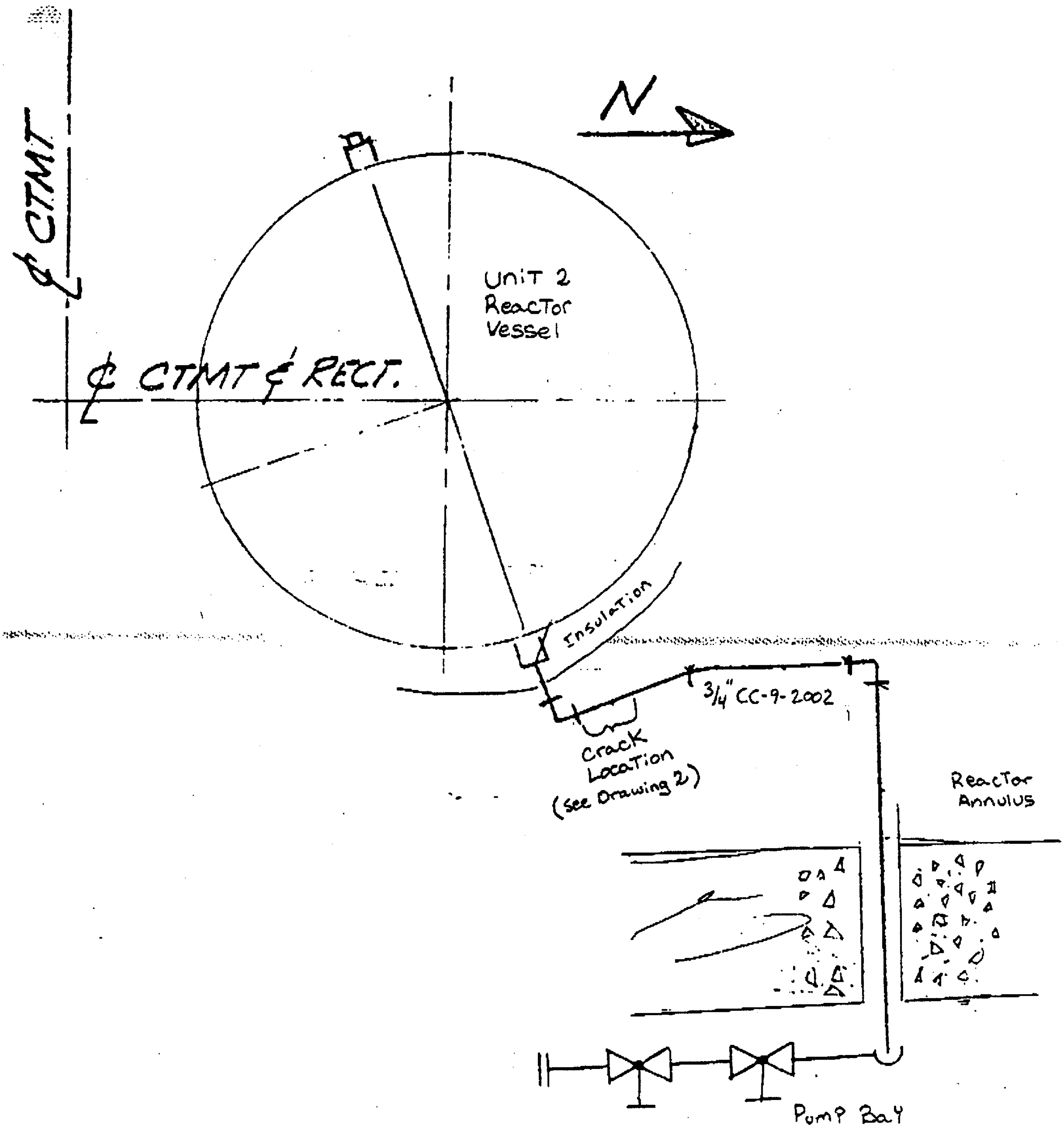
REFERENCES

BGE DRAWINGS
- 62-729
- 62-255
- FSK-MP-714
- FSK-MP-3206
- 12017-18
- 12017-03
- 12017-17
- 12393-08
- 12393-07

BGE PROCEDURES
- RV-22
- RV-78

POSRC MEETINGS
- 94-009
- 94-010
- MEETING ON 3/17/94

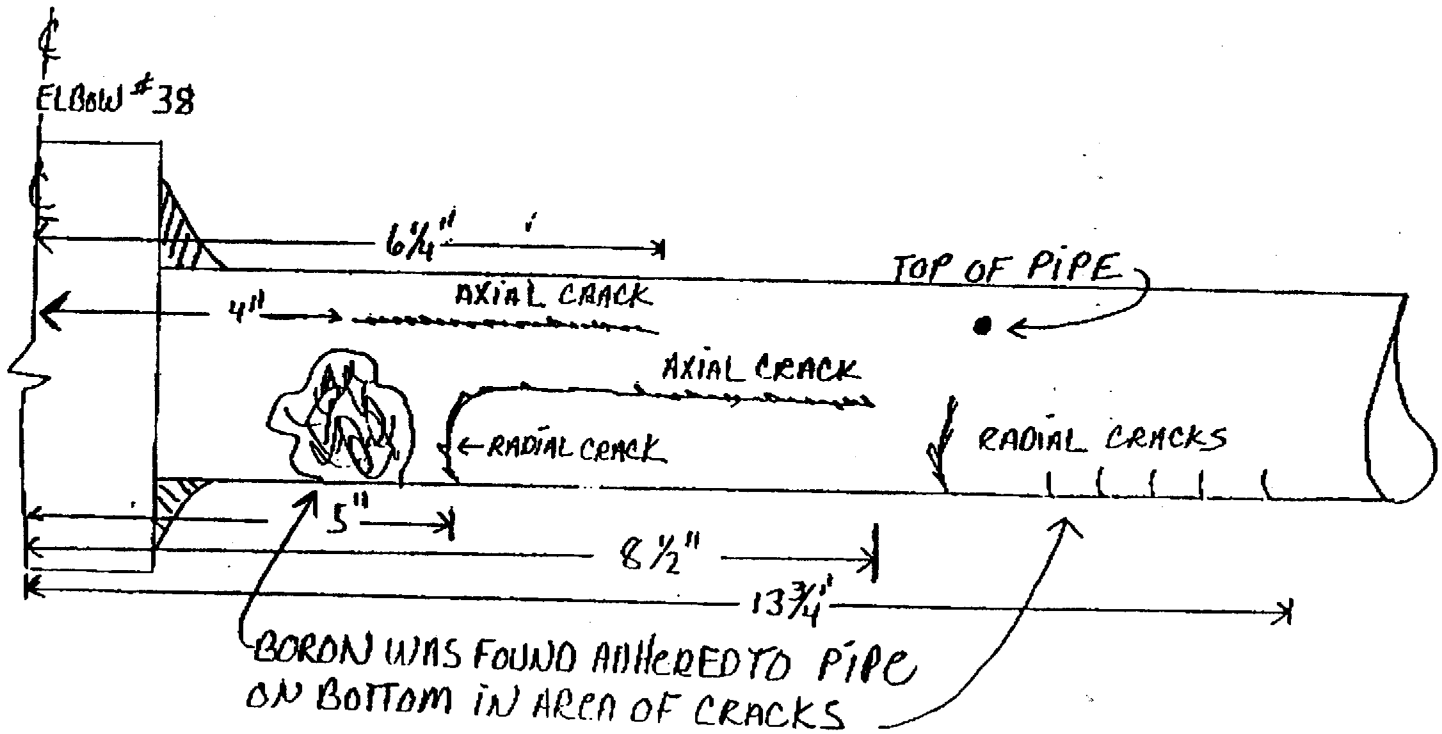
MAINTENANCE ORDERS
- 2199400201
- 2199402249
- 2199400984
- 2199400106
- 2199400194
- 1199400773
- 1199400378


℄ CTMT
N
Unit 2
Reactor
Vessel
℄ CTMT & RECT.
Insulation
3/4" CC-9-2002
Crack
Location
(See Drawing 2)
Reactor
Annulus
Pump Bay

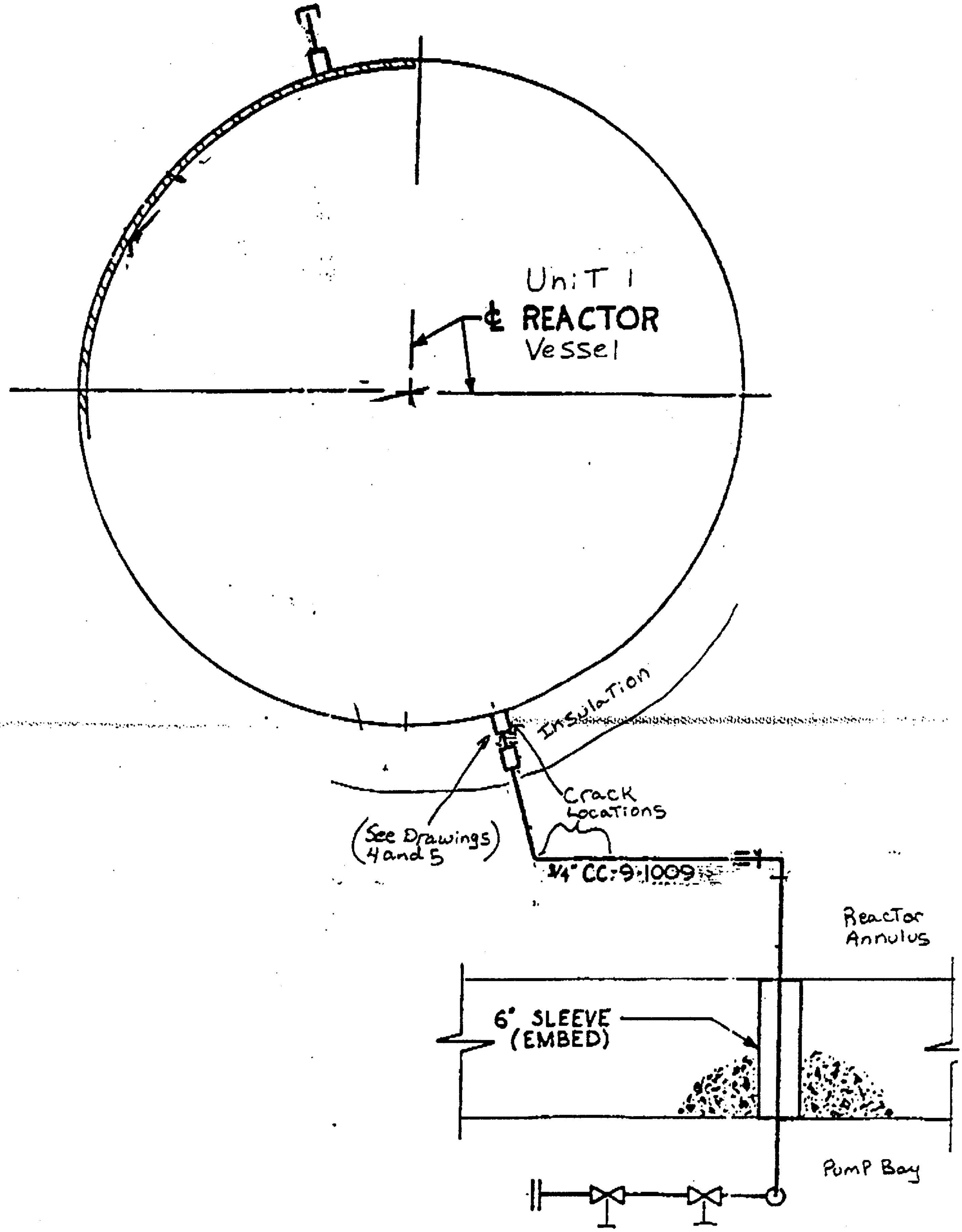
Drawing 1

NDE DATA SHEET NO. 94-PT-2-005

U-2 RV LEAKAGE MONITORING LINE



Drawing 2

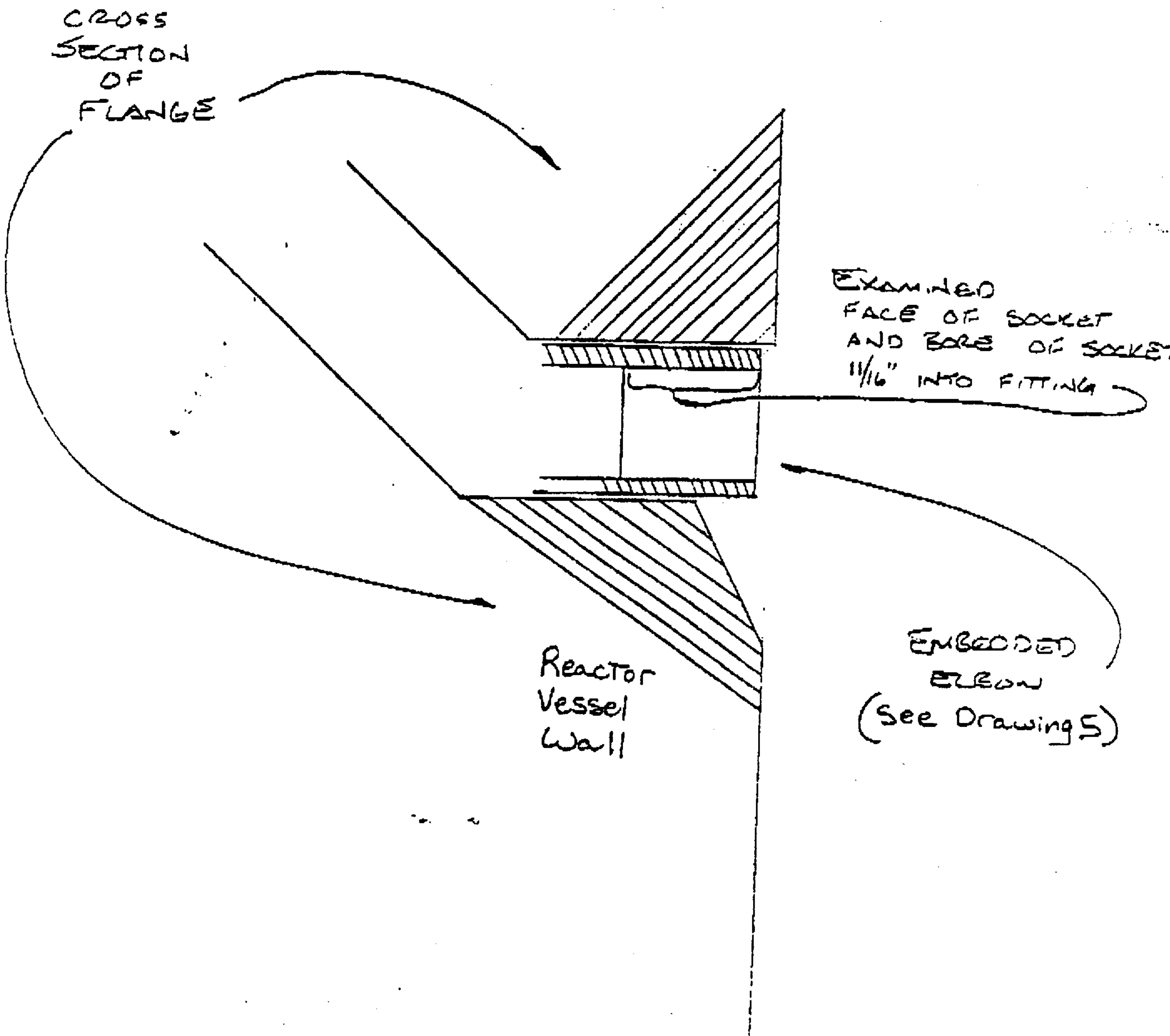


Drawing 3

(Not To Scale)

19400378
3-6-94

Unit-1

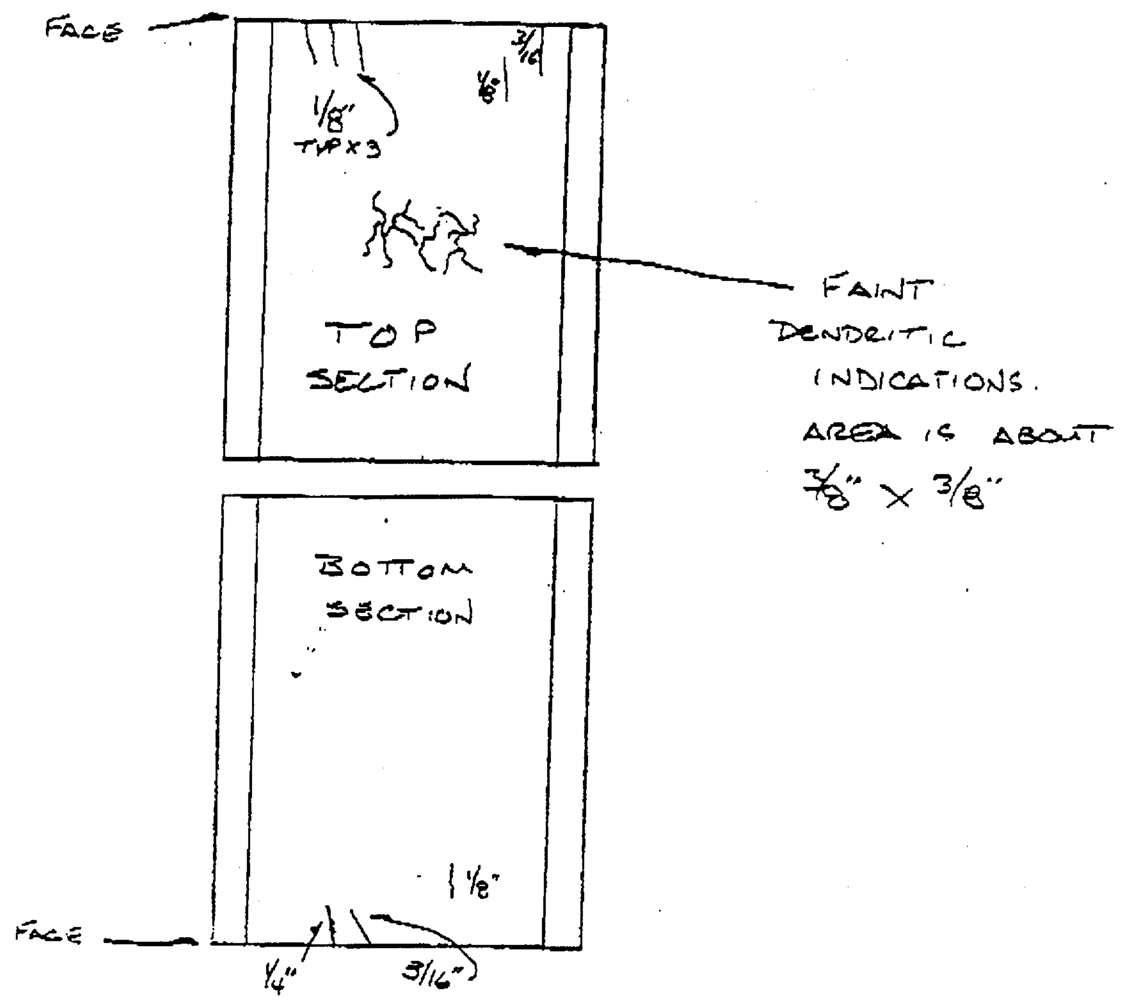


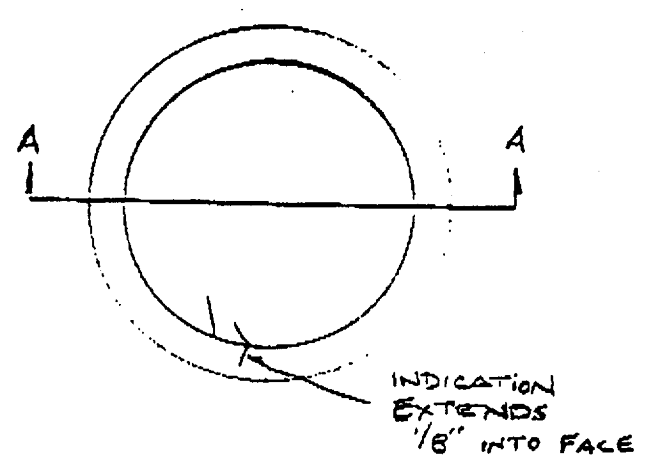
Drawing 4

Unit - 1

19400378
3-6-94

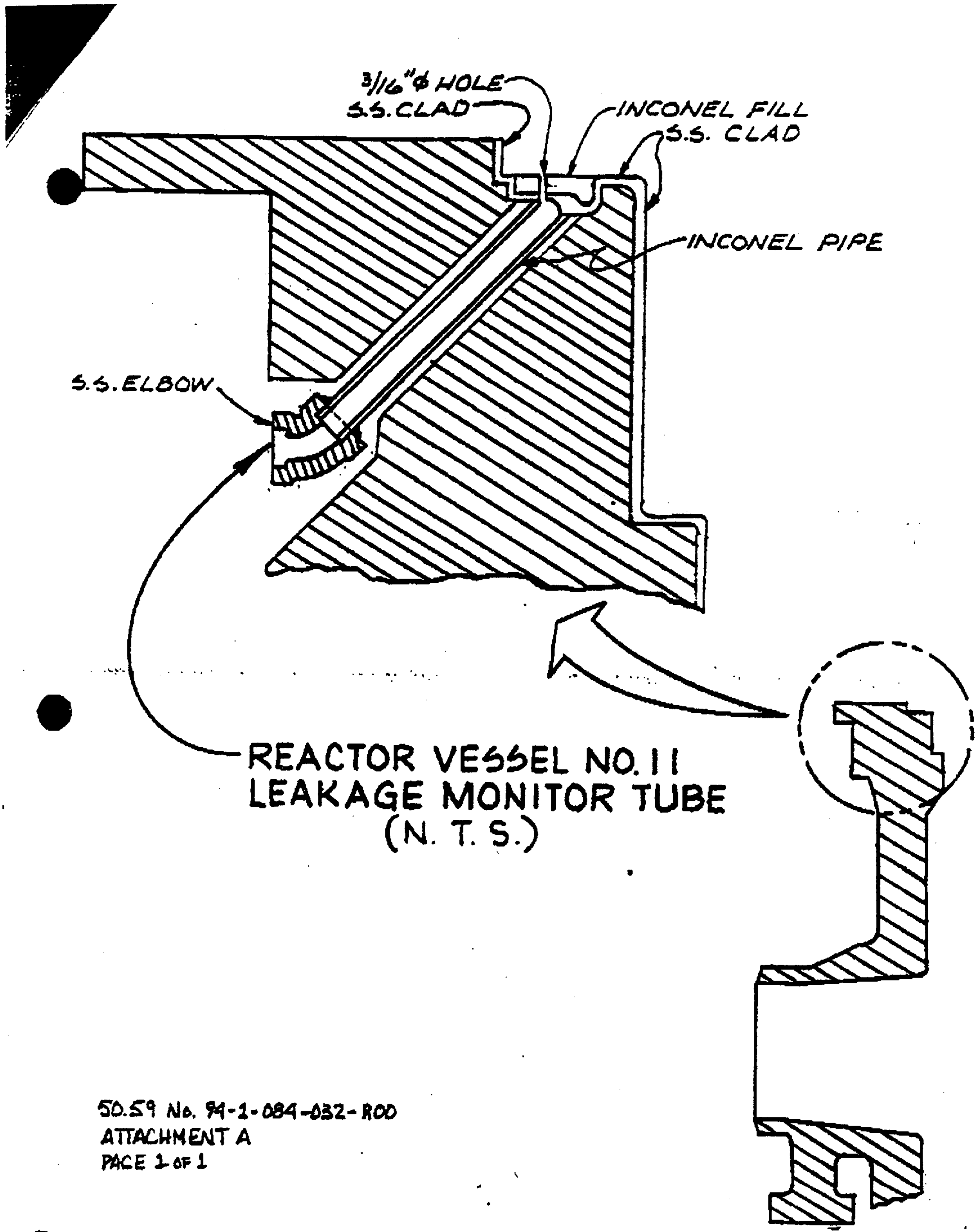
ENLARGEMENT OF SOCKET
BORE ONLY





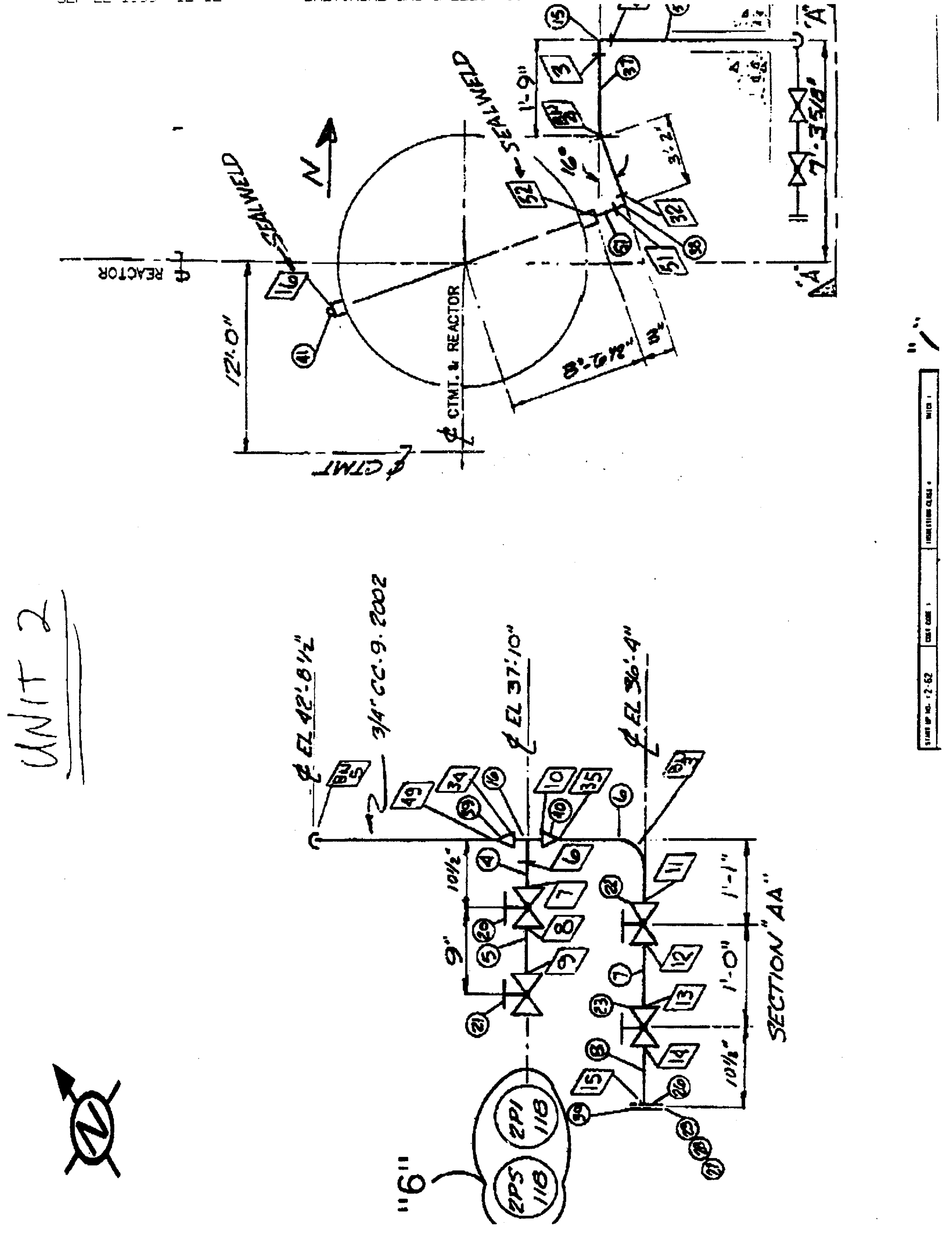
SOCKET
FACE

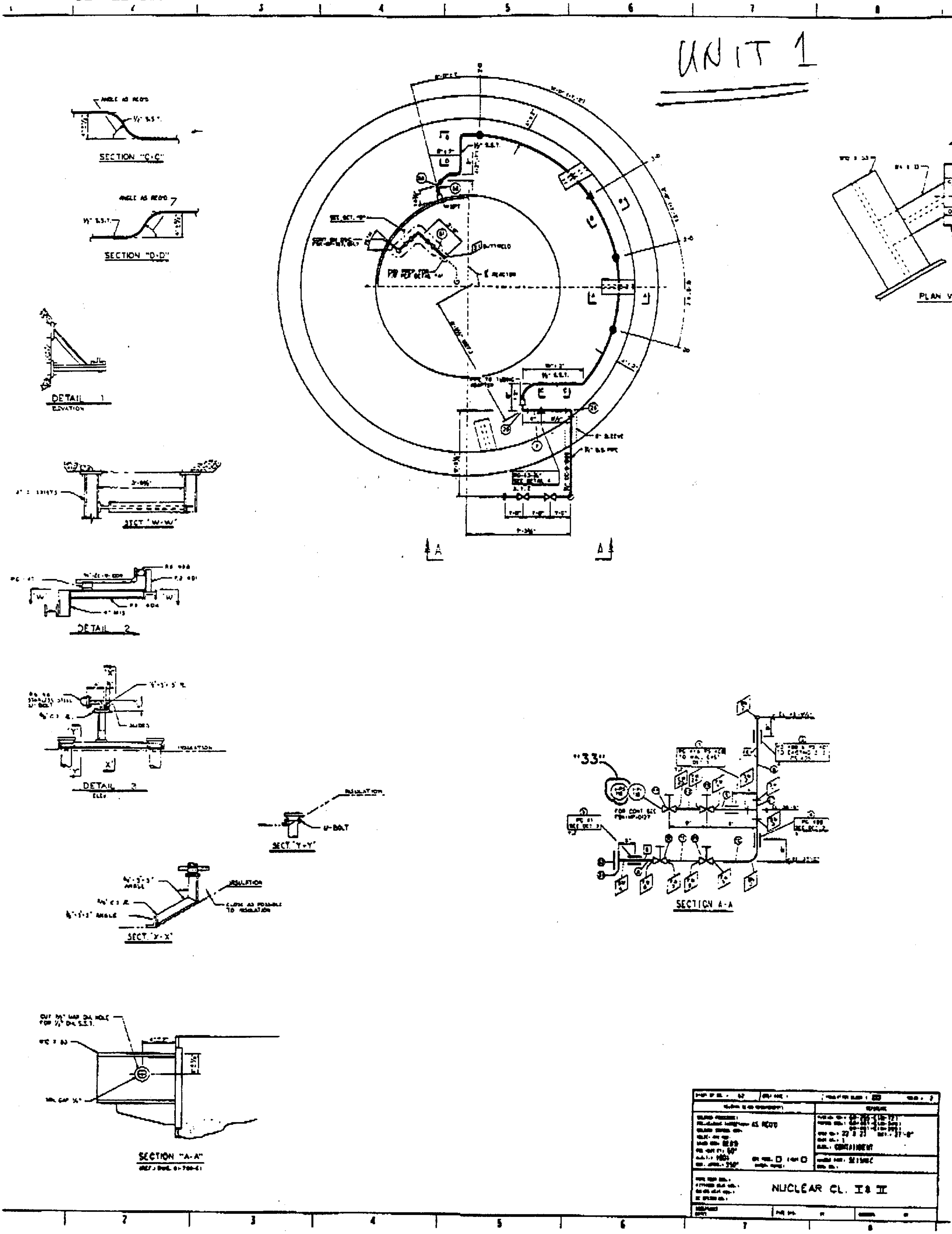
Drawing 5



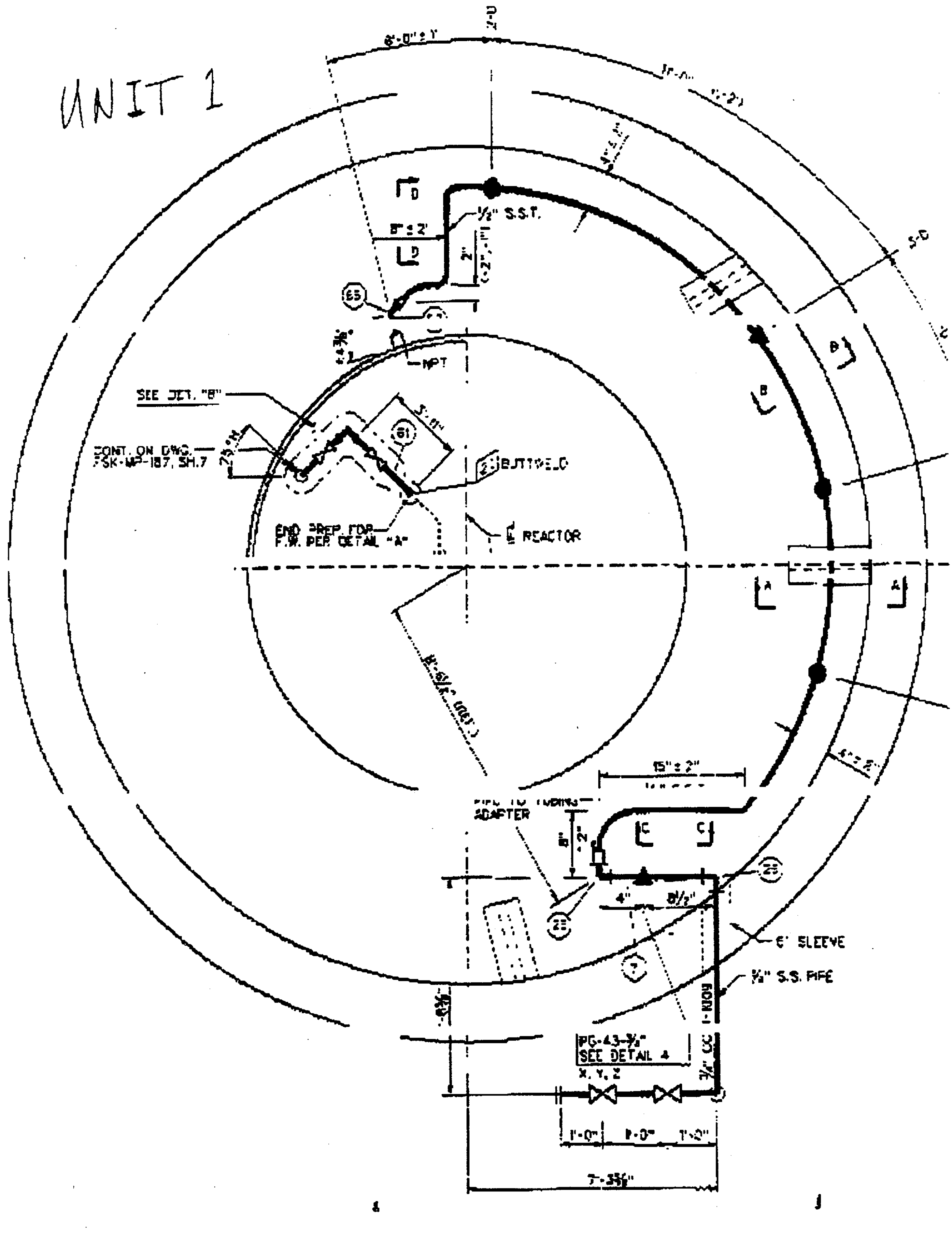
REACTOR VESSEL NO. 11
LEAKAGE MONITOR TUBE
(N. T. S.)

50.59 No. 94-1-084-032-R00
ATTACHMENT A
PAGE 1 OF 1


UNIT 2
"6"
2PS 118
2PI 118
SECTION "AA"
3/4" CC-9-2002
℄ EL 42'-8 1/2"
℄ EL 37'-10"
℄ EL 36'-4"
1'-1"
1'-0"
10 1/2"
9"
10 1/8"
℄ REACTOR
℄ CTMT. & REACTOR
℄ CTMT
SEALWELD
SEALWELD
N
12'-0"
8'-6 1/2"
16°
1'-9"
3'-2"
7'-3 5/8"
"A"
"A"



UNIT 1
SECTION "C-C"
SECTION "D-D"
DETAIL 1
ELEVATION
SECT "W-W"
DETAIL 2
DETAIL 3
SECT "Y-Y"
U-BOLT
INSULATION
SECT "X-X"
SECTION "A-A"
"33"
SECTION A-A
PLAN VIE
BUTTWELD
CONTAINMENT
NUCLEAR CL. I & II


UNIT 1
½" S.S.T.
SEE DET. "B"
CONT. ON DWG. FSK-MP-187, SH.7
BUTTWELD
END PREP FOR F.W. PER DETAIL "A"
℄ REACTOR
NPT
15" ± 2"
ADAPTER
4"
8½"
6" SLEEVE
½" S.S. PIPE
PG-43-¾"
SEE DETAIL 4
X, Y, Z
¾" CC
1'-0"
7'-3⅝"

NOTE:

Steps 6.2.1 and 6.2.2 may be performed prior to or in parallel with Subsection 6.1 and prior to Initial Conditions 4.6.3 through 4.6.13, and prior to draining refuel pool. (Provided isolation valves are isolated and tagged.)

Subsection 6.4 (RV Closure Head Leveling) may be performed anytime prior to or concurrent with Step 6.2.4. Subsection 6.34 is performed before Subsection 6.4.

Subsection 6.2 may be worked anytime before lifting the RV head at Step 6.5.7.

Steps 6.5.2 through 6.5.6 may be performed anytime before lifting and traveling the RV head in Step 6.5.7.

6.2 Reactor Vessel O-Ring Leak-off Line [B-95-012]

1. **ATTACH** a catch device to contain water coming from leak-off line. ______
2. **ENSURE** Rad Con sets up a Hepa Filter in the area where water will be discharged. ______
3. **REMOVE** leak-off line blind flange and Flextallic gasket. ______
4. **OBTAIN** Operations permission and **OPEN** valves 1-RC-101 and 1-RC-102 for Unit-1 or 2-RC-101 and 2-RC-102 for Unit-2. ______
5. **BLOW** leak-off line clear with approximately 10 psi air at the flange o-ring leak-off line hole, for approximately 30 seconds. ______

NOTE:

Steps 6.2.6 through 6.2.8 may be performed at any time after leak-off line blow down.

6. **OBTAIN** Operations permission and **CLOSE** valves 1-RC-101 and 1-RC-102 for Unit-1 or 2-RC-101 and 2-RC-102 for Unit-2.
7. **INSTALL** leak-off line blind flange and Flextallic gasket.
8. **TORQUE** flange bolts to 150 (145 to 155) ft. lbs. in two increments. (75 and 150 ft-lbs)

OI 3.2.3.2.1-3 – additional information

Although BGE did not find any aging mechanism plausible for the pressurizer clad (with the exception of Fatigue, which is managed by the FMP), BGE has agreed to inspect the cladding inside one pressurizer. This inspection will encompass an area including portions of the top head and/or portions of the cylinder within one foot of the head weld. This location was chosen based on the potential for residual stresses from fabrication (due to the head/cylinder transition) and access/ALARA considerations. BGE did not choose this location based on any analysis that quantitatively evaluates the cladding stresses in the pressurizer. The location chosen represents a qualitative judgement only.

The most significant portion of the Haddam Neck cracking occurred around the pressurizer circumference slightly below the normal waterline. The initiating effect for this cracking was not determined conclusively. Postulated causes were a cold spray during a low water level transient or alternately some discrete event predating initial startup. In either case these effects would not qualify as age-related degradation and would therefore not suggest a potential problem area for CCNPP.

BGE is aware of no basis to suppose that the heater wells of the CCNPP pressurizers would be more susceptible to clad cracking than any other location. BGE has already performed an inspection, by remote video camera, of one pressurizer lower head region (the heater penetrations are on the pressurizer lower head in CE designs) adjacent to a penetration and found no evidence of cracking.

Based on this, BGE considers the location selected appropriate for a one-time inspection for pressurizer clad cracking.

Additional information following teleconference of 9/21/99

- The surge nozzle for the CCNPP pressurizers is at the very bottom of the pressurizer. The inspection access will be through the top of the pressurizer. Interference due to heater well supports and other internal parts makes inspection of the surge nozzle area impractical.
- The normal water level region is as easily accessible as the area previously chosen by BGE (the area including portions of the top head and/or portions of the cylinder within one foot of the head weld). This region can easily be chosen instead, if NRC Staff prefers. There would be no impact on ALARA, outage schedule, etc.

PROPOSED REVISION TO OPEN ITEM 3.2.3.3.1.1-2 RESPONSE:

BGE performed an aging management review evaluation for external surfaces of piping systems. The evaluation considered all combinations of materials and environments. The evaluation considered Calvert Cliffs practices that contain necessary guidance to retard or prevent corrosion on external surfaces of piping components. Those practices include painting and protective coatings application standards and thermal insulation standards.

The staff has indicated that TGSCC of the RCS piping would be the result of the presence of chlorides from insulation, concrete, or contaminated surfaces. However, water, residual stresses, and a specific temperature range are also required for the onset of chloride-induced TGSCC. To address the non-plausibility of TGSCC of RCS piping in more detail, two of the four contributing factors will be addressed – a source of chlorides and a source of water.

The following CCNPP documentation contains information relative to the insulation installed on RCS piping: Engineering Specification 6750-M-336, Specification for Reactor Coolant System and Steam Generators Insulation; Engineering Standard ES-015 (formerly DS-015), Thermal Insulation; and Dwg. 83240, Thermal Insulation for Piping and Equipment.

The first of these documents, Specification 6750-M-336, is the specification that was used for the original installation of the insulation on the RCS piping. The insulation originally installed on the system was either: (1) reflective insulation composed of all 304SS components, or (2) mineral wool sandwiched between an external stainless steel shell and an inner layer of stainless steel foil to cover all surfaces and edges. The specification required that the mineral wool material be treated with sodium silicate to act as an inhibitor against SCC and that the chloride content be no more than 100 ppm.

Engineering Standard ES-015 identifies that after years of RCS insulation installation and plant operation resulting in gradually increased containment heat load, a replacement program for the original mineral wool insulation was initiated. At that time, an engineering evaluation was performed and the decision was made to use fiberglass insulation in place of the mineral wool. BGE Drawing 83240 was created at the onset of this program to provide a controlled document that maintained an as-built status of all insulation installed in both CCNPP units. This drawing indicates, for RCS piping, where the original insulation is still installed as well as where the replacement fiberglass insulation has been installed.

ES-015 identifies three critical design characteristics for insulation on safety-related piping. They are the insulation thermal conductivity, the insulation density (for weight considerations), and the insulation corrosivity. It further identifies that insulation materials used at CCNPP, per design specifications, are to have less than 200 ppm leachable chlorides to control the possibility of insulation-caused SCC. It also further identifies that the addition of leachable inhibitors (usually sodium and silicon) within insulation materials can further neutralize corrosive effects.

BGE Drawing 83240 contains all of the SS piping classes that are identified as being within the scope of license renewal in the RCS Aging Management Review Report. All of these piping classes are insulated and covered with stainless steel jackets.

TGSCC of the external surfaces of RCS piping is not plausible because the stainless steel jacket and limited chloride content of the insulation prevents exposure of the piping surfaces to the wetted chloride environment needed for TGSCC to occur.

Additionally, the hypothesis that a leak could cause the wetting of piping externals with chloride contaminated water resulting in TGSCC is an event-driven scenario, not an aging or aging management scenario. Any kind of leak that could cause such wetting in containment would be detected and corrective actions would be taken accordingly. It would be a short-term anomaly.

Further, after obtaining and performing detailed reviews of complete copies of the LERs from the list sent to CCNPP as examples of the occurrence of SCC within the industry, it was found that these events do not involve aging or aging management. They were event-driven scenarios of one form or another.

It is, therefore, BGE's conclusion, because of the CCNPP insulation design considerations and because only an event-driven scenario could result in the remote possibility of the wetting of RCS piping with chloride contaminated water, that TGSCC of the RCS piping is not plausible.

OI 3.2.3.2.1-3 – additional information

Although BGE did not find any aging mechanism plausible for the pressurizer clad (with the exception of Fatigue, which is managed by the FMP), BGE has agreed to inspect the cladding inside one pressurizer. This inspection will encompass an area including portions of the top head and/or portions of the cylinder within one foot of the head weld. This location was chosen based on the potential for residual stresses from fabrication (due to the head/cylinder transition) and access/ALARA considerations. BGE did not choose this location based on any analysis that quantitatively evaluates the cladding stresses in the pressurizer. The location chosen represents a qualitative judgement only.

The most significant portion of the Haddam Neck cracking occurred around the pressurizer circumference slightly below the normal waterline. The initiating effect for this cracking was not determined conclusively. Postulated causes were a cold spray during a low water level transient or alternately some discrete event predating initial startup. In either case these effects would not qualify as age-related degradation and would therefore not suggest a potential problem area for CCNPP.

BGE is aware of no basis to suppose that the heater wells of the CCNPP pressurizers would be more susceptible to clad cracking than any other location. BGE has already performed an inspection, by remote video camera, of one pressurizer lower head region (the heater penetrations are on the pressurizer lower head in CE designs) adjacent to a penetration and found no evidence of cracking.

Based on this, BGE considers the location selected appropriate for a one-time inspection for pressurizer clad cracking.

Proposed response to OI 2.2.3.23.2.1-1

From the Statements of Consideration (SOC) for 10CFR Part 54, " …. the Commission agrees that for purposes of 54.4, the scope of 50.49 equipment to be included within 54.4 is that equipment already identified by licensees under 50.49(b). Licensees may rely upon their listing of 10CFR50.49 equipment, as required by 10CFR50.49(d), for purposes of satisfying 54.4 with respect to equipment within the scope of 50.49."

As discussed in BGE Letter to the NRC, dated 2/19/99; "Response to Request for Specific Information Needed for the Staff Evaluation of Environmental Qualification for License Renewal' (BGE Response to NRC Request No. 4a), the establishment of expected normal plant operating ambient temperatures should be representative of that which is expected to be seen by the component during its installed life. The cavity cooling system, including the ductwork, provides the normally expected ambient temperature for this area.

The equipment, which provides the normally expected environment, is not specifically required to be identified as 10CFR50.49. The cavity cooling ductwork is in this category. Failure of cavity cooling will not prevent the execution of the critical safety functions identified in 10CFR50.49(b)(1) during and following a design basis accident. During or following a design basis accident, the cavity cooling function is assumed to be unavailable.

Furthermore, per the letter from NRC to NEI, the cascading failure effects characterized by 10CFR54.4(a)(2) need not be applied to 10CFR54.4(a)(3) scoped items.

Please note that it does not follow that failure of the cavity cooling system or any of its components, can occur without an operability evaluation of the impact. This situation would be treated as a degraded condition and entered into our corrective action process. Operability of affected SSCs would be evaluated, including affects on 10CFR50.49(b) equipment. Continued plant operation would be determined based on the operability evaluation conclusions, until such time (commensurate with the safety significance of the issue) that corrective actions can be taken to correct the degraded condition.

Confirmatory Item 3.2.3.2.1-3

To manage aging effects associated with stress corrosion cracking (SCC) of Alloy 600 RPV components, the applicant relies on its Alloy 600 program. The applicant stated that the Alloy 600 program does not predict PWSCC to be an issue for the period of extended operation. The applicant plans to continue its periodic visual inspections to verify this prediction. The staff requests that the applicant confirm that control element drive mechanisms (CEDMs) are included in the periodic inspections via the Boric Acid Corrosion Inspection Program, confirm that cracking of CEDMs has been considered for a 60-year life, and provide the results of the susceptibility evaluation for the CEDMs relative to this time frame, and provide operating experience from inspections of CEDM nozzles at Calvert Cliffs Nuclear Power Plant (CCNPP), if available.

BGE Response

CEDMs are Included

The reactor vessel head penetrations (of which the CEDMs are a subset) are required to be examined, during each refueling outage or forced outage in which the plant attains Mode 5 or 6, by the Boric Acid Corrosion Inspection Program, BGE Administrative Procedure MN-3-301 Revision 2, "Boric Acid Corrosion Inspection Program" (Reference 10). The examination is a VT-2 examination (a visual examination capable of ½ mil resolution) to detect boric acid or other signs of leakage.

Confirmation

The susceptibility predictions for cracking of CEDMs have been performed for a 60-year life.

Results of Susceptibility Evaluation

Enclosure (1) to Reference (11) was a histogram showing the number and identity of pressurized water reactor plants grouped according to the predicted time from January 1, 1997, until a certain size crack existed in the worst vessel head penetration. The three groupings were < 5 EFPY, 5-15 EFPYs, and > 15 EFPYs. The benchmark probability is the probability equal to that of a 75% through-wall crack in one control rod drive mechanism penetration in the D.C. Cook Unit 2 RV head, at the time of the volumetric inspection of the D.C. Cook 2 RV head penetrations in 1994. This probability is 34%.

Using the current methodology (the EPRI Model) outlined in Enclosure (6) to Reference (11), a 34% chance of a 75% through-wall crack is reached in the year 2034 for Calvert Cliffs Unit 1. Therefore, in the year 2029, Calvert Cliffs Unit 1 will reach the <5 EFPY category as defined by the histogram. ~~It would, therefore, be reasonable for~~ BGE will conduct a volumetric inspection of vessel head penetrations at a date no later than 5 years prior to the date at which the probability of a 75% throughwall crack in at least one CEDM becomes 34%. This date will be determined using the aforementioned EPRI model or an improved model that may be developed in the future. The current model prediction for a 34% probability of a 75% throughwall crack in the Unit 1 CEDM nozzles ~~to be scheduled for~~ would require BGE to schedule this inspection for no later than 2029. ~~or later.~~

For Calvert Cliffs Unit 2, the probability of one RV head penetration developing a 75% through-wall crack is only 16% at the end of the extended license period. A 34% probability of a 75% through-wall crack in not reached until 47.6 EFPY from January 1, 1997, which falls in the year 2044 or later (the actual date depends on the capacity factor of Unit 2). Therefore, BGE does not intend to schedule any volumetric inspections of the Unit 2 CEDM penetrations between now and the end of extended life in 2036. However, if a revised model were applied which indicated a 34% probability of a 75% throughwall crack in a CEDM was reached prior to the end of the extended license period for Unit 2, a volumetric inspection would be scheduled accordingly.

It should be noted that the methodology of determining the PWSCC susceptibility of CEDM penetrations is subject to change as better models are developed or new information about variables influencing PWSCC comes to light. Baltimore Gas and Electric Company will employ the most current, accurate methodology available to refine the susceptibility predication and adjust our inspection planning accordingly.

Operating Experience

VT-2 inspections have been performed during each refueling outage at Calvert Cliffs Unit 1 and Unit 2. No indications of boric acid leakage due to pressure boundary leakage of Alloy 600 CEDM nozzles have been observed. The CEDM nozzles have not been volumetrically inspected since the Units began commercial operation.

OI 3.2.3.2.1-4

Proposed Response:

BGE has compared the CVCS and RCS components applicable to this issue. The material of construction for the applicable components in both systems is austenitic stainless steel (CVCS: ASTM A-376 or A-312, Type 304 Stainless Steel, and RCS: ASTM A-376 or A-312, Type 304 or Type 316 Stainless Steel). The material and fabrication requirements for the components in both systems were identical with respect to the factors that influence stress corrosion cracking. The piping materials used to construct the CVCS and RCS small-bore piping are susceptible to SCC when exposed to chloride-containing solutions at temperatures in excess of 150°F. Type 304 and type 316 stainless steel have similar susceptibility to SCC when exposed to chlorides. Sensitization of austenitic stainless steels such as type 304 or type 316 can increase the susceptibility to SCC and allow SCC at lower chloride concentrations, particularly as dissolved oxygen increases. Sensitized areas would only exist in the heat-affected zone (HAZ) of welds. The same group of weld procedures were used in the fabrication of both systems. The fabrication specification for both systems required a 350°F maximum interpass temperature. An interpass limit temperature is generally specified to limit the amount of time the base material can be exposed to temperatures which produce sensitization (800-1200°F). Therefore, a similar potential for SCC due to sensitization exists in both the CVCS and RCS small bore piping. A higher assurance level due to more rigorous inspection and testing requirements for RCS ensures the fabrication of the RCS small bore piping is equal to or better than the CVCS from a quality standpoint. Therefore, in terms of the probability of degradation due to fabrication irregularities, the CVCS bounds the RCS.

The differences in operating environments were discussed in BGE's response to this item in Reference (a) (7/2/99 BGE letter), demonstrating that the CVCS environment is more severe. BGE therefore maintains the conclusion that the ARDI to be performed on the CVCS System small bore piping will bound the small bore piping in the RCS.

Proposed response to OI 3.2.3.2.1-2 (Vessel Flange Leak Off Line)

BGE discussed operating experience with the Reactor Pressure Vessel Head Closure Seal Leakage Detection Lines on pages 4.1-8 and 4.1-46 of the BGE LRA. The Unit 2 line had cracked, due to an ever increasing concentration of contaminants in the vicinity of the cracking due to repeated boil off of the liquid left in the line at the end of each refueling, eventually reaching levels high enough to cause TGSCC. The lines in both Units were subsequently replaced. Measures were taken to prevent recurrence in that the lines were to be drained and blown dry every refueling outage. The practice of blowing the lines dry changed this aging scenario entirely.

The BGE LRA characterized this scenario as plausible aging with a mitigative program (blowing the lines dry). Because that program actually eliminates the cause of the experienced cracking, no cracking is expected. Therefore no discovery program was deemed necessary and none was identified in the LRA.

NRC staff subsequently requested an additional program (presumably a discovery program), saying that the proposed program was merely mitigative. BGE believes no purpose would be served by a discovery program, based on the reasoning given above. BGE also believes that because the aging scenario was changed entirely by the practice of blowing the lines dry, we should have characterized this scenario as having no aging effects plausible, with a BGE commitment to continuing the practice of blowing the lines dry during each refueling outage.

The key factor involved here is that, through operating experience and our corrective action program, we not only took corrective action, but action to prevent recurrence. The operating experience with cracking is therefore related to a scenario that no longer exists.

Calvert Cliffs Nuclear Power Plant Units 1 and 2
List of Programs Credited for Aging Management

LRA Section	System	Status	Program	Credited For	Group Description	Aging Effect
5.6	Containment Spray	New	ARDI Program	Program for discovery and management of general corrosion, crevice corrosion, and/or pitting for internal surfaces of piping, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs by identifying and correcting degraded conditions.	PP, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs	General Corrosion, Crevice Corrosion, and/or Pitting
5.6	Containment Spray	Existing	CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program"	Program for mitigation and discovery of general corrosion for external surfaces of piping, CKVs, CVs, HVs, HXs, MOVs, and PUMPs that are exposed to borated water (due to leakage) by performing visual inspections.	PP, CKVs, CVs, HVs, HXs, MOVs, and PUMPs that are exposed to borated water (due to leakage).	General Corrosion
5.6	Containment Spray	Existing	CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems"	Program for mitigation of general corrosion, crevice corrosion, and/or pitting for internal surfaces of piping, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs that are exposed to borated water (as process fluid) by controlling chemistry conditions.	PP, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs) that are exposed to borated water (as process fluid).	General Corrosion, Crevice Corrosion, and/or Pitting
5.6	Containment Spray	Existing	CCNPP Technical Procedure CP-206, "Specification and Surveillance Component Cooling/Service Water System"	Program for mitigation of general corrosion, crevice corrosion, and/or pitting for internal surfaces of the SDCHXs that are exposed to chemically-treated water from the CC System by controlling chemistry conditions in the CC System.	SDCHXs	General Corrosion, Crevice Corrosion, and/or Pitting
5.16	Saltwater System	New	ARDI Program	Discovery of the effects of crevice corrosion, general corrosion, MIC, and pitting for the affected components.	Internally lined PP, CKVs, CVs, HVs, RVs, TIs, and TPs	Crevice Corrosion, General Corrosion, MIC, and Pitting

Calvert Cliffs Nuclear Power Plant Units 1 and 2
List of Programs Credited for Aging Management

LRA Section	System	Status	Program	Credited For	Group Description	Aging Effect
5.16	Saltwater System	New	ARDI Program	Discovery of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, selective leaching, and elastomer degradation for the affected components that are not inspected by the PM Program.	Internally lined PP, BSs, CKVs, CVs, HVs and PUMPs	Crevice Corrosion, Galvanic Corrosion, General Corrosion, MIC, Pitting, and Elastomer Degradation
5.16	Saltwater System	New	ARDI Program	Discovery of the effects of crevice corrosion, general corrosion, and pitting for the shell side of the affected heat exchangers and susceptible areas of the Unit 1 plate and frame heat exchangers.	Shell Side of the CC and SRW HXs and susceptible areas of the Unit 1 plate and frame HXs	Crevice Corrosion, General Corrosion, and Pitting
5.16	Saltwater System	Modified	CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program" For affected components: Repetitive Tasks 10122063 through 10122068; 10122096 through 10122102; 20122067 through 20122072; 20122100 through 20122106; 10122086 through 10122088; 10122107 through 10122110 and 20122092 through 20122094; Checklists MPM04194, MPM01180, and MPM01181 Procedure PUMP-03	Discovery of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation for the affected components.	Internally lined PP, BSs, CKVs, CVs, HVs and PUMPs	Crevice Corrosion, Galvanic Corrosion, General Corrosion, MIC, Particulate Wear Erosion, Pitting, And Elastomer Degradation
5.16	Saltwater System	Existing	CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program"For affected components: Checklists IPM10000 and IPM10001	Mitigation of the effects of general corrosion for the affected components.	ACCs, CVs, and PCVs, with air internal environment	General Corrosion

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Calvert Cliffs Nuclear Power Plant Units 1 and 2
List of Programs Credited for Aging Management

LRA Section	System	Status	Program	Credited For	Group Description	Aging Effect
5.16	Saltwater System	Existing	CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program"For the affected components: Repetitive tasks 10152023; 10152024; 20112006; 20112027; 20152020; and 20152021 Checklists MPM00005 and MPM00006	Discovery of the effects of crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation for the tube side of the affected heat exchangers.	CC and SRW HXs	Crevice Corrosion, Erosion Corrosion, General Corrosion, MIC, Pitting, and Elastomer Degradation
5.16	Saltwater System	Modified	CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program"For the affected components: Checklists MPM05000 and MPM05101 (modification needed)	Discovery of the effects of the crevice corrosion, general corrosion, MIC, and pitting for the tube side of the affected heat exchangers.	ECCS Pump Room Air Coolers	Crevice Corrosion, General Corrosion, MIC, and Pitting
5.16	Saltwater System	Existing	CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program"For the affected components: Repetitive tasks 10122095 and 20122099	Discovery of the effects of crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting for the affected components.	FOs	Crevice Corrosion, Erosion Corrosion, MIC, Particulate Wear Erosion, and Pitting
5.16	Saltwater System	Existing	CCNPP Technical Procedure TP-206, "Specifications and Surveillance for Component Cooling/Service Water System"	Mitigation of the effects of crevice corrosion, general corrosion, and pitting for the shell side of the affected heat exchangers.	CC and SRW HXs	Crevice Corrosion, General Corrosion, and Pitting
5.16	Saltwater System	Modified	Structure and System Walkdowns (MN-1-319)	Discovery and management of the effects of general corrosion on SW System Bolting	SW System Bolting	General Corrosion

Component [illegible]	
ACC	Accumulat
CKV	Check Valve
CV	Control Valve
FE	Flow Element
FO	Flow Orifice
HV	Hand Valve
HX	Heat Exchanger
MOV	Motor Operated Valve
PCV	Pressure Control Valve
PUMP	Pump/Driver Assembly
PP	Piping
RV	Relief Valve
TE	Temperature Element
TI	Temperature Indicator
TP	Temperature Test Point

3.2.3.2.1-4

BGE has compared the CVCS and RCS components applicable to this issue. The fabrication standards have been reviewed and found to be similar for components in both systems. CVCS piping involves ASTM A-376 or A-312 for Type 304 Stainless Steel, and RCS piping involves ASTM A-376 or A-312 for Type 304 Stainless Steel or Type 316 Stainless Steel.

The differences in operating environments were discussed in BGE's response to this item in Reference (a) (7/2/99 BGE letter), demonstrating that the CVCS environment is more severe. BGE therefore maintains the conclusion that the ARDI to be performed on the CVCS System small bore piping will bound the small bore piping in the RCS.

3.2.3.2.1-4

Proposed Response:

BGE agrees that the use of the word 'random' in BGE letter of 7/2/99 implies an assumption. However, BGE did not make that assumption of random versus localized failures in concluding that the aging management approach described provides reasonable assurance that the function of the CEA shroud will be maintained. BGE agrees with what appears to be an NRC assumption that these failures would not necessarily be random, and BGE apologizes for the confusion.

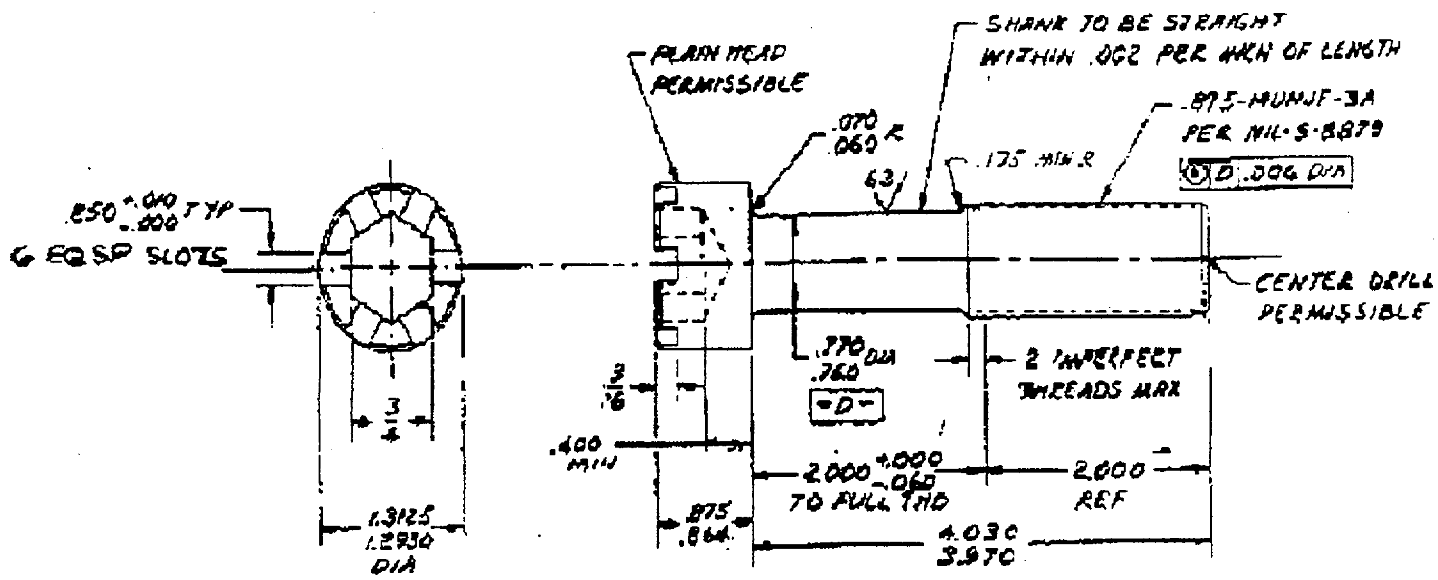
In addition, BGE offers the following additional information, which builds on the level of assurance that the function will be maintained:

The only failure of these bolts that would affect an individual bolt's lateral support and alignment function would be a crack across the interface plane between the CEA Shroud and the Fuel Assembly Alignment Plate. However, the geometry of the bolts is such that, should a failure occur, it is not likely to occur at that interface. A diagram of the bolt is shown below. Based on the geometry shown, experience with actual failures of similar bolts in different applications, and the fact that the threads are rolled, BGE believes areas likely to fail are areas such as the transition between the bolt head and the shank, the transition between the shank and the threaded area, and the shank itself.

These bolts are inserted from the bottom up. The diagram below does not show the interface plane, but it is in the threaded region of the bolt. This means that if a bolt fails below the interface plane (towards the head), the portion above the failure will provide the lateral support and alignment function, and if the bolt fails above the interface plane, the lower part of the bolt would still be threaded and would maintain the function.

More than three (or more than six for a dual shroud) bolts would have to fail at the interface plane to put the plant in an unanalyzed condition. Entry into such a condition is highly unlikely due to the most likely failure mechanism and its relationship to the critical function, as described above. Undetected entry into such a condition is even more unlikely since bolt failures in the unthreaded portion would eventually be detected when bolt locking tabs break free.

Therefore, considering all of the information pertinent to this aging scenario, there is reasonable assurance that the aging will be managed such that the function will be maintained in the period of extended operation.



(15) SOCKET HEAD CAP SCREW

SCALE: FULL SIZE

NEXT ASSY E-XXXX-164-031

A) TENSILE PROPERTIES (ROOM TEMP)
  (a) 130,000 PSI MIN TENSILE
  (b) 85,000 PSI MIN YIELD @ 0.2 % OFFSET
  (c) ELONGATION 15% IN 4D
B) MFG. PROCEDURES PER STANDARD PRESSED STEEL B-186 OR EQUIV AS APPLICABLE
C) HEAD TO SHANK FILLET TO BE COLD WORKED
D) THREADS TO BE ROLLED AFTER ASE HARDENING
E) SOCKET HEAD TO BE STD 1960 SERIES
F) SOCKET HEAD TO BE FREE OF BURRS.

3.2.3.2.1-2 (Reactor Vessel Flange Leak Off Line)

Based on review of this particular aging scenario and the past cracking experience, BGE has determined that SCC is not plausible for the leakoff lines. BGE made changes to the maintenance approach for this leakoff line following the experienced cracking, which has eliminated the cause of the cracking. The cause was residual refueling water left in the line over several refueling cycles, causing a continually wet environment and a concentration of contaminants. The lines are now blown dry during each refueling outage, and BGE commits to continuing this practice. If the inner O-ring of the reactor vessel flange leaks, reactor coolant will be introduced into these lines. However, there will not be a concentration effect and the reactor coolant will be blown out during the next refueling. Our reassessment concludes that the practice of periodically blowing these lines dry, which BGE formerly credited for mitigation, is actually preventive and makes SCC not plausible in this stainless steel-in-air scenario.

3.1.5.3-1 (NSR in QA Program)

BGE will include, in the final safety analysis report and/or in our quality assurance program description, an explicit commitment that those BGE Appendix B quality assurance program elements specifically related to corrective actions, confirmation processes, and administrative controls, apply to non-safety-related SSCs that are subject to AMR for license renewal.

void swelling

BGE does not consider void swelling as plausible. However, if it does occur, gross deformation will be detected by VT-3 inspections already required by ASME Section XI.

3.10.3.2.1 and 4.1.3-2 (tendons TLAA)

As stated in NRC letter dated August 12, 1999, "the staff understands that BGE intends to manage the tendon prestress force TLAA as an aging management program under 54.21(c)(1)(iii)." NRC requested information in four areas, which is provided below:

1) The parameters monitored or inspected per 10 CFR 50.55a(b)(2)(ix)(b).

There is a discussion of BGE's current surveillance program in UFSAR section 15.6 (part of the "Technical Requirements Manual".) Key areas are as follows:

- Normalized tendon liftoff forces.
- Wire sample
- Visual inspections

Although paragraph 10 CFR 50.55a(b)(2)(ix)(B) is limited to evaluation of prestressing forces in consecutive surveillances, we plan to inspect all of the parameters listed in (ix).

2) The acceptance criteria such that projected tendon force trending remains above the predicted lower limit.

ASME Code Section XI, IWL-3221 gives the requirements for acceptance by examination, including the provision that "the prestressing forces for each type of tendon ... and the measurement from the previous examination indicate a prestress loss such that predicted tendon forces meet the minimum design prestress forces at the next scheduled examination." If we would not meet this criterion, the options are acceptance by evaluation (IWL-3222) and acceptance by repair / replacement activity (IWL-3223).

3) Corrective actions that include systematic retensioning of tendon population to ensure the adequacy of prestressing force.

Potential actions include:

- "Bootstrapping," or increasing the tension in all or part of the tendons.
- Replacing selected tendons with new tendons.
- Reanalysis

4) Operating experience as applicable to tendon force monitoring.

Other plants have observed prestressing wire corrosion, end anchorage failures, water in the vertical tendons, and greater than expected relaxation due to solar heating.

BGE found broken wires in the 1997 inspection, and submitted reports to the NRC dated August 28, 1997, October 28, 1997, and May 14, 1998. At that time, we thought it prudent to replace a number of tendons.

3.10.3.2.1 and 4.1.3-2 (tendons TLAA) (continued)

Since 1997, we researched tendon sheathing material ("grease";) ran tests on grease replacement methods; wrote a specification for and received bids for tendon replacement. We also contracted a specialty consulting firm for additional analyses to verify and/or refine the UFSAR values for containment strength.

In addition, we performed visual inspections on over half of the vertical tendons in 1999, including all previously categorized as having "severe corrosion." We found a few more broken wires. Since this is a low number, we have another specialty consulting firm reevaluating the wire break projections for future years. We are reevaluating our position, and expect to submit additional information to the NRC later this year.

In conclusion, BGE feels this adequately addresses the issues and demonstrates BGE's ability to effectively manage this TLAA.

Calvert Cliffs
License Renewal Application
Discussions with the
US Nuclear Regulatory Commission

Dick Heibel, Manager - Nuclear Projects
Carl Yoder, Project Director - LR
Barth W. Doroshuk, President - CNS, Inc.

October 12, 1999

BGE

Constellation Nuclear Services

Current Status

- All Open and Confirmatory Items have reached an agreed to success path:
  - Items from August 12 NRC letter
  - UFSAR OI, per August 27 meeting summary

Current Status

- BGE will provide a new (and final) version of LIST (for information) by mid-November.

SER Open Item 3.0-1

“The content of the final safety analysis report (FSAR) supplement is dependent upon the final bases for the staff’s safety evaluation, as will be reflected in a subsequent revision to this report. In addition, improved guidance is being developed for updating the contents of FSARs under 10 CFR 50.71(e). Therefore, the resolution of the information that needs to be added to the FSAR will be addressed after the other open and confirmatory items are resolved, prior to issuance of a renewed license. The content of the FSAR will be tracked as an Open Item.”

From 8/27/99 meeting summary

"... the staff concluded that while 10 CFR 50.21(d) did not require a FSAR supplement to be updated, not updating the FSAR supplement placed the burden on the staff for the development of the basis of information needed to support the 10 CFR 54.29 finding. To this end, as described in NRR Office Letter 805 "License Renewal Application Review Process," the staff has to articulate, and is obligated to document, findings critical to its review."

From 8/27/99 meeting summary

“. . . The **first** such option is that the FSAR supplement be revised prior to licensing by the applicant to include the appropriate information as a consequence of the staff's review. The **second** option is that the staff provide a list of information the staff relied upon with the final safety evaluation report (SER) in conjunction with a license condition that this information be controlled under 10 CFR 50.59 until it is placed in the FSAR in accordance with the existing 10 CFR 50.71(e) requirements for updating the FSAR. The staff would verify the changes later and the license condition would expire once the information had been incorporated.”

From 8/27/99 meeting summary

"... The **third** option is similar to the second option with the distinction that the applicant would develop the list using the SER, responses to open items, and questions; and the NRC would review and approve the list. Finally, the **fourth** option would impose a license condition requiring that all commitments, contained in the license renewal application, related correspondence, and the SER be controlled in accordance with the 10 CFR 50.59 process until the FSAR was updated in accordance with 10 CFR 50.71(e)."

THE LIST

BGE agreed to provide a list that would assist the NRC staff in identifying the basis for its SER conclusions. BGE is not required to provide the LIST to secure new licenses.

Such a list would identify the programs credited for License Renewal in the LRA. The list would not contain descriptions of programs suitable for the UFSAR.

BGE would continue to utilize the Commitment Tracking System and the UFSAR update process to ensure the programs/ commitments, etc. are incorporated into the CLB, as appropriate, following issuance of renewed licenses.

What happens now?