UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

September 8, 2003

EA-03-141

James J. Sheppard, President and
Chief Executive Officer
STP Nuclear Operating Company
P.O. Box 289
Wadsworth, Texas 77483

SUBJECT: SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION - NRC SPECIAL INSPECTION TEAM REPORT 05000498/2003008 AND 05000499/2003008 AND EXERCISE OF ENFORCEMENT DISCRETION

Dear Mr. Sheppard:

On July 28, 2003, the US Nuclear Regulatory Commission (NRC) completed a Special Inspection at your South Texas Project (STP) Electric Generating Station, Units 1 and 2, facility. The enclosed report documents the inspection findings, which were discussed during a public exit meeting on July 28, 2003, with you and other members of your staff. An NRC Staff Evaluation discussing the subject of this Special Inspection was forwarded to you on July 31, 2003.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

The inspection examined the events associated with your discovery of minor reactor coolant leakage from two bottom-mounted instrument penetrations at STP, Unit 1. This leakage was determined to be from the reactor coolant system pressure boundary, a condition prohibited by the Technical Specifications. Also, a second Technical Specification violation resulted because the leakage indicated that reactor coolant system structural integrity was not met. Although this constitutes two violations of NRC requirements, the conditions for taking traditional enforcement action were not satisfied, in that these violations did not have actual consequences (as defined in Section IV.A.5.c of the Enforcement Policy), impede the regulatory process, or result from willful acts. Additionally, this issue was evaluated under the reactor oversight process. We concluded that your actions did not contribute to the degraded condition and, thus, no performance deficiency was identified. A qualitative risk assessment was performed and determined that this was an issue of very low significance. Your monitoring program for bottom-mounted instrumentation leakage has proven to be effective. Your actions in response to the identified leakage demonstrated an appropriate safety perspective and your corrective actions were appropriate and well-supported. Based on these facts, the NRC has decided to exercise enforcement discretion in accordance with Section VII.B.6 of the Enforcement Policy and will not take enforcement action for these violations. The NRC staff has issued Regulatory Issue Summary 2003-13, Information Notice 2003-11, and Bulletin 2003-02, to address this issue generically.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Dwight D. Chamberlain
Acting Deputy Regional Administrator

Dockets: 50-498
50-499
Licenses: NPF-76
NPF-80

Enclosure:
NRC Inspection Report 05000498/2003008 and 05000499/2003008
w/Attachment: Supplemental Information

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ADAMS: ■ Yes ☐ No Initials: RLB
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RLBywater	WCSifre	NFO'Keefe	MFRunyan	MAMitchell
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D:ACES	D:OE	C:DRP/A	Acting DRA	
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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-498 50-499
Licenses:	NPF-76 NPF-80
Report No:	05000498/2003008 05000499/2003008
Licensee:	STP Nuclear Operating Company
Facility:	South Texas Project Electric Generating Station, Units 1 and 2
Location:	FM 521 - 8 miles west of Wadsworth Wadsworth, Texas 77483
Date:	May 5 through July 28, 2003
Inspectors:	R. Bywater, Senior Reactor Analyst (Team Leader) N. O'Keefe, Senior Reactor Inspector W. Sifre, Reactor Inspector M. Runyan, Senior Reactor Analyst M. Mitchell, Senior Materials Engineer, NRR
Accompanying Personnel:	S. Doctor, Ph.D., Consultant
Approved By:	D. Chamberlain Acting Deputy Regional Administrator

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR05000498/2003008; IR05000499/2003008; 05/05-07/28/2003; South Texas Project Electric Generating Station; Units 1 and 2; Special Inspection Team Report.

The inspection was conducted by a team of regional inspectors, an Office of Nuclear Reactor Regulation senior materials engineer, and a nondestructive testing consultant. The inspection identified two violations of NRC requirements involving leakage from the reactor coolant system pressure boundary. The significance of most violations is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or assigned a severity level after NRC review. The NRC program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

Technical Specification 3.4.6.2.a requires that the reactor coolant system pressure boundary has no leakage. Technical Specification 3.4.10 provides requirements for structural integrity of the reactor coolant system. Leakage was identified on April 12, 2003, from two bottom-mounted instrumentation penetrations on the STP, Unit 1, reactor pressure vessel. These penetrations form a portion of the reactor coolant system pressure boundary and are required for structural integrity. Therefore, this condition was a violation of Technical Specifications 3.4.6.2.a and 3.4.10.

In this case, no licensee performance deficiency was identified associated with the material condition described and the conditions for taking traditional enforcement action were not satisfied. Based on a qualitative risk assessment, the issue was of very low significance. The licensee's corrective actions were acceptable. Therefore, the NRC has decided to exercise enforcement discretion in accordance with Section VII.B.6 of the Enforcement Policy and refrain from issuing enforcement action for the violations.

A. <u>NRC-Identified and Self-Revealing Findings</u>

None.

B. <u>Licensee-Identified Violations</u>

None.

REPORT DETAILS

1.0 Special Inspection Scope

The team conducted a special inspection in response to the licensee's identification of apparent reactor coolant system (RCS) pressure boundary leakage from two bottom-mounted instrumentation (BMI) penetrations on the South Texas Project (STP), Unit 1, reactor vessel. The team used Inspection Procedure 93812, "Special Inspection," to accomplish the objectives of the team's charter.

The charter contained the following elements:

- Develop a chronology of BMI penetration inspection scope and results.

- Review records associated with the installation of BMI penetrations during original construction and identify techniques and materials used for BMI installation.

- Review the licensee's program for inspection of pressure boundary leakage associated with the reactor vessel, including inspection techniques and scope, periodicity, and the results of past inspections.

- Review the licensee's root and probable cause determination for completeness and accuracy including review of any relevant plant-specific and industry (foreign and domestic) operating experience.

- Review and assess the adequacy of the licensee's evaluation of the extent-of-condition as it relates to other penetrations in Unit 1, as well as Unit 2.

- Review the licensee's risk determination including the operational aspects of recovery from a bottom head loss-of-coolant accident.

- Review and assess the adequacy of nondestructive examination (NDE) qualification techniques.

- Review and assess the licensee's prompt and long-term corrective actions to address the root and probable causes of the condition. Assess the adequacy of repair activities and independently verify information submitted in support of NRC review of any American Society of Mechanical Engineers (ASME) Code repairs.

- Review the circumstances associated with the leaking BMI penetrations and identify potential generic safety concerns in a timely manner to regional management.

To accomplish the charter elements, the team:

- Interviewed licensee and contractor personnel including engineers, operators, NDE analysts, and technicians

- Witnessed NDE qualification activities at vendor laboratories and independently analyzed data obtained from NDE inspections performed at the facility

- Reviewed corrective action documents, fabrication records, test records, modification packages, engineering documents, procedures, and drawings

- Performed independent analyses of risk significance

- Witnessed control room simulator scenarios

- Witnessed installation of repairs and performance of Code-required inspections

2.0 Documentation of Charter Elements

2.1 Description of Issue and Chronology

STP, Units 1 and 2 are four-loop Westinghouse-designed pressurized water reactor (PWR) nuclear steam supply system units with each unit having a rated thermal power output of 3853 megawatts. The units' reactor pressure vessels (RPVs) were fabricated from low-alloy pressure vessel steel and each RPV bottom head has 58 penetrations for the insertion of in-core neutron flux monitoring instrumentation, known as BMI penetrations. Figure 1 shows a cross-sectional view of a typical BMI penetration. Each penetration consists of a nominal 1.5-inch diameter hole bored in the RPV bottom head, with an Inconel Alloy 600 nozzle inserted into the hole and attached to the RPV bottom head by a partial penetration J-groove weld at the inside surface. An annular clearance gap exists between the nozzle and the RPV head. Outside of the RPV, each nozzle is welded to a stainless steel instrument guide tube which extends to the BMI seal plate. Thimble tubes are inserted into the core through the guide tubes and nozzles prior to plant operation. In-core flux monitoring instrumentation is then inserted into the thimbles during surveillance testing. The nozzles, attachment welds, guide tubes, and thimble tubes are part of the RCS pressure boundary.

On April 12, 2003, during Refueling Outage 1RE11 at STP, Unit 1, the licensee performed a planned bare metal inspection of the RPV bottom head as part of its Boric Acid Corrosion Control (BACC) program. The inspection identified white deposits that had extruded from the annular gap around BMI Penetrations 1 and 46. The licensee quantified the amount of observed deposits as approximately 150 milligrams around Penetration 1 and 3 milligrams around Penetration 46. No wastage was identified on the exposed RPV surface. Results of chemical and isotopic analyses of the deposits confirmed that they originated from the RCS and that they were, on average, about 4 years old. Further, the licensee concluded that RCS pressure boundary leakage was the most likely source of the deposits. An estimate of the total quantity of leakage from the RCS was that it was less than 50 gallons over the estimated 4 year period.

Based on this conclusion, the licensee entered Technical Specification (TS) action statements for RCS pressure boundary leakage (TS 3.4.6.2.a) and failure to maintain RCS structural integrity (TS 3.4.10). These action statements required that the plant be maintained in the cold shutdown mode and less than 130 °F, respectively.

The licensee made a notification to the NRC in accordance with 10 CFR 50.72 on April 13, 2003. The licensee entered the issue into the corrective action program as Condition Report 03-6736. The licensee also initiated Condition Report 03-6768 to evaluate the BMI issue for potential impact on STP, Unit 2.

The licensee had performed bare metal visual inspections of the Unit 1 RPV bottom head during every refueling outage and during 11 forced outages. None of these inspections had found evidence of leakage. The most recent inspections were conducted during the previous refueling outage (1RE10), in October 2001, and during a forced outage on November 20, 2002.

The licensee provided the NRC with a letter, dated, April 24, 2003, which documented commitments to investigate the extent of the condition, determine the root cause, implement corrective actions, and brief the NRC on the results. A public meeting was conducted with the NRC on May 1, 2003, to discuss the licensee's action plan and on May 5, 2003, the NRC chartered a special inspection team.

The licensee conducted NDE inspections of the BMI nozzles, J-groove welds, and portions of the reactor vessel shell during May and June of 2003. The inspections confirmed that the repair scope was limited to Penetrations 1 and 46. On June 5, 2003, the licensee presented its inspection results and repair plans to the NRC at a public meeting and, on June 11, 2003, submitted Licensee Event Report (LER) 05000498/2003-003-00. The licensee performed repairs using the half-nozzle repair technique in June. Following completion of the repairs, cleaning of all 58 guide tubes was performed to correct a previously identified condition involving difficulty in the insertion and removal of thimble tubes. Material samples were taken from the nozzle and weld material of Penetrations 1 and 46 for destructive evaluation in July 2003.

On July 11, 2003, the licensee documented the basis for Unit 1 readiness for restart in a letter to the NRC, which was discussed at a public meeting on July 17, 2003. Following the presentation of the results of this special inspection at a public exit meeting, the NRC issued a letter and Staff Evaluation on July 31, 2003, documenting the acceptability of restart of STP, Unit 1, and continued operation of STP, Unit 2.

2.2 BMI Nozzle Installation and Service

a. Inspection Scope

The team reviewed drawings and other design and fabrication documents to determine the techniques and materials used for BMI nozzle installation. The team reviewed attributes of material composition, installation, and service application known to contribute to cracking of Inconel Alloy 600 materials in other RCS applications to identify potential significant contributors for the observed BMI leakage. Potential plant operation and maintenance contributors were also considered.

b. Observations

Installation Issues

The STP, Unit 1 RPV was constructed by Combustion Engineering at its Chattanooga, Tennessee facility in 1978. The RPV bottom heads for both of the STP units were fabricated from typical low-alloy pressure vessel steel (American Society for Testing and Materials Classification A-533 Grade B, Class 1), and are 5.38 inches in thickness with a 0.22-inch layer of stainless steel cladding on the inside surface. Each of the 58 BMI penetration nozzles has a nominal wall thickness of 0.45 inches and an inside diameter (ID) hole of 0.60 inches. At room temperature conditions, a clearance gap of 0.001 to 0.004 inches (1 to 4 mils) between the Inconel Alloy 600 nozzle and the low-alloy steel RPV head was included in the design of the penetrations. The nozzles were fabricated from 1.75-inch diameter Inconel Alloy 600 (an austenitic nickel-based alloy) bar stock and the J-groove welds were fabricated from Inconel Alloy 82/182, the weld wire equivalent of Inconel Alloy 600 base material.

The certified mill test reports for the material heats used in nozzle fabrication confirmed that they had material composition properties that were typical of Inconel Alloy 600 nozzles that have experienced primary water stress corrosion cracking (PWSCC) in other RCS applications.

Fabrication records indicated that the bar stock was extensively machined during the fabrication process on both the ID and outside diameter (OD) of the nozzle in order to obtain the dimensions and clearances noted above prior to being welded into the RPV bottom head. Residual stresses and surface cold working produced during material processing are known to contribute to PWSCC sensitivity.

The team determined that the procedure used for installing the BMI nozzles in the lower RPV head followed the applicable ASME Code requirements. Fabrication records showed that the nozzle installation process included the following steps after the bore holes and J-groove weld preps were installed in the RPV lower head:

- Apply alloy 82/182 weld butter layer to the J-groove weld preps,

- Stress relieve the RPV lower head,

- Tack-weld nozzles in place,

- Apply root pass of the J-groove weld, grind as necessary, and inspect by liquid penetrant (PT) examination (repair as necessary),

- Apply first ½ inch of the J-groove weld, grind as necessary, and inspect last layer by PT examination (repair as necessary),

- Check nozzles for perpendicularity using a bulls-eye level and cold-straighten as necessary,

- Apply second ½ inch of the J-groove weld, grind as necessary, and inspect last layer by PT examination (repair as necessary),

- Check nozzles for perpendicularity using a bulls-eye level and cold-straighten as necessary,

- Complete welding, grinding, and inspection/repair for each ½-inch weld thickness (if necessary),

- Check nozzles for perpendicularity using a bulls-eye level and cold-straighten as necessary,

- Grind crown of the J-groove weld and inspect by PT examination.

Nozzle installation records documented that some amount of cold straightening was performed, but the records did not identify which nozzles were affected. From discussions with the licensee, it appears that nozzle straightening to achieve perpendicularity was performed by hammering. This would add additional residual stresses to both nozzle and weld, and could have occurred up to three times for any nozzle. Additionally, the records did not identify which nozzles may have had weld repairs performed. However, this information was not required to be documented. Two acceptance tests were performed for the nozzle installation (other than the PT examinations of the welds). These tests included: (1) a “rod” test, which involved pulling a steel rod through each nozzle to check for drag (indicative of nozzle bending) and (2) a “ball drop” test, which involved dropping a steel ball through the nozzle bore to ensure it passed freely (indicative of acceptable ovality). The acceptance tests were satisfactory for all of the nozzles. It is important to note that no volumetric examination of the welds was required or performed.

No post-weld heat treatment was performed of the completed lower RPV head after nozzle installation. Therefore, residual stresses from the welding process were not relieved. Residual stress from welding processes is known to contribute to PWSCC sensitivity.

Although records provided no details of repairs performed to nozzles during installation, results from the May 2003 BMI penetration visual inspections indicated that several nozzles had significant grinding marks on the OD of the nozzle. This indicated some weld repairs probably took place during fabrication. Grinding and weld repair would add residual stress to the weld area. Additionally, results from the May 2003 BMI ultrasonic (UT) examinations showed that all nozzles had some anomalous conditions at the nozzle-to-weld interface, possibly indicating a lack of weld fusion or other anomalous weld condition. These conditions could provide an area to concentrate stresses and initiate a crack.

Operations Issues

The STP, Units 1 and 2 RPV lower head temperature during power operation is 561 °F (T_{cold}). Elevated temperature of operation is a known environmental contributor to PWSCC and the T_{cold} at the STP units is one of the highest in the industry. The RPV upper head temperature had also been one of the highest in the industry. Prior to RCS T_{hot} reduction efforts before the steam generator replacement outage in 2000 and installation of an RPV bypass flow modification during the steam generator replacement outage, the RPV upper head temperature during power operation had been as high as 630 °F. After the modification, RPV upper head temperature was maintained at T_{cold}. No indications of leakage from any Inconel Alloy 600 penetration had been identified during the bare metal visual inspections performed of the RPV upper head each outage. Although the STP T_{cold} is relatively high compared to other PWRs, it is still substantially lower than the RPV upper head temperatures of most PWRs where cracks in Inconel Alloy 600 control rod drive mechanism (CRDM) nozzles had been identified.

The team reviewed unit operating history to identify any unusual service conditions, such as excessive stresses due to heat-up and cool-down cycles, excessive flow-induced vibration, and resin-intrusion events that could be expected to contribute to BMI penetration cracking. No unusual service conditions were identified from these sources.

An item that had been a longstanding material condition issue was reviewed by the team involving difficulty in the insertion and removal of BMI thimble tubes during outages. Typically at PWRs, these tubes were inserted and withdrawn with minimal manual force. However, at STP, Unit 1, several thimble tubes required mechanical assistance to allow their insertion and removal, resulting in application of greater than 1000 pounds of force. Difficult thimble insertion had been experienced since initial startup of STP, Unit 1. One BMI penetration had been abandoned as a result of this condition because its thimble had become stuck inside of its nozzle or guide tube. A similar condition did not exist for STP, Unit 2. The team questioned whether the application of force to insert or remove thimbles had an adverse impact on the BMI nozzles. Upon further review, the amount of force permitted in the licensee’s procedure was well within the allowable stress levels, so any effects were negligible. The team also noted that the two nozzles with leaks did not have a thimble tube sticking problem. However, during BMI repair efforts, the licensee discovered that BMI Penetrations 1 and 46 contained foreign material, which was determined to be fine shavings of Inconel Alloy 600. As a result of this discovery, the licensee cleaned all of the BMI guide tubes. All thimbles were inserted easily following this effort. The licensee’s evaluation of the source of the foreign material had not been completed by the completion of this inspection.

2.3 <u>Reactor Coolant System Leakage Monitoring and RPV Pressure Boundary Leakage Inspection Program</u>

2.3.1 Methods and Frequency

a. <u>Inspection Scope</u>

The team reviewed the licensee’s programs, procedures, and equipment capabilities for detecting and classifying RCS leakage inside the reactor containment building (RCB). The team reviewed the Updated Final Safety Analysis Report (UFSAR), system descriptions and operating procedures for leakage detection systems, and discussed their design and operation with station personnel. The team also reviewed the licensee's program, procedures, and results of inspections for the detection of leakage from the RCS pressure boundary.

b. Observations

The licensee's programs and equipment for detecting RCS leakage satisfied design and licensing basis requirements and commitments. However, some areas for improvement in classifying leakage were identified by the team.

There were several methods available to the licensee to detect RCS leaks of various sizes inside the RCB. Very small leaks should be identified through visual inspections of the RCS pressure boundary by observing the accumulation of boric acid residue. Larger leaks, up to and including loss-of-coolant accident (LOCA)-sized breaks, would be identified through systems designed to detect the leakage. These include instruments to collect and measure sump flow and level, radiation monitors, and humidity detectors.

Visual Inspections

The BMI leaks were identified during a visual inspection called a boric acid walkdown. The licensee implements this inspection as part of its BACC program commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." These inspections were performed using Procedure 0PGP03-ZE-0033, "RCS Pressure Boundary Inspection for Boric Acid Leaks," during each refueling outage and during forced outages lasting > 72 hours when an inspection has not been done within the last 90 days. The team determined that the licensee had performed these inspections throughout the life of the plant and the records indicated that no indications of boric acid had been identified in the BMI penetration area previous to the April 2003 inspection. The RPV bottom head is contained in an insulating box structure with no insulation in direct contact. Insulation panels may be removed to allow visual inspection of the RPV lower head and BMI penetration nozzles. Procedure 0PGP03-ZE-0033 also required inspection of other locations in the RCS to detect leaks. However, since stainless steel comprised most of the RCS except for the RPV and pressurizer, the boric acid walkdowns look at a limited number of components and was not all-inclusive of the RCS pressure boundary.

Leakage Detection Systems

Technical Specification 3.4.6.2 provides limits for RCS leakage. These limits include 10 gpm "identified leakage," 1 gpm "unidentified leakage," and zero "pressure boundary leakage." Identified leakage is leakage from known sources, such as safety and relief valves, and pump or valve seals, which are typically hard-piped to collection tanks so that they can be monitored and not mask any potentially serious leak should one occur. Unidentified leakage is leakage from any RCS source which has not been determined, such as valve stem packing glands or other mechanical joints. Pressure boundary leakage is leakage from a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

Technical Specification 3.4.6.1 provided the requirements for systems designed to detect RCS leakage. These systems included the containment atmosphere radioactivity monitoring system (gaseous and particulate) and the containment normal sump and flow monitoring system. As stated in the TS bases and UFSAR, these systems were provided to monitor and detect leakage from the RCS pressure boundary. The systems were designed to meet the recommendations of NRC Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973. Other systems or methods also exist which provide indication of RCS leakage, including RCB humidity monitors, other RCB radiation monitors, and RCS water inventory balance calculations.

Level in the normal and secondary sumps is monitored by the plant computer. Flow from the sump pumps to the radioactive liquid waste system is also monitored. When either level changes or average flow exceed 1 gpm, the plant computer alarms in the control room. It will alarm again for increases in 1 gpm increments. There is also a control board alarm (independent of the plant computer) which alerts operators that a sump high-high level exists. This informs operators that either the sump pump activated at a high level did not start, or leakage exceeds the capacity of the first sump pump. By design, this system is intended to meet the Regulatory Guide 1.45 recommendation of being capable of detecting an RCS leakage increase of 1 gpm within an hour. Operators had control board indication of when the sump pumps started and a flow totalizer and sump level indicator which were independent of the plant computer.

The team identified that the licensee did not have an annunciator response procedure for the sump monitor alarms. Further, the licensee did not have a defined process to investigate the source of leakage increases until total leakage reached an alarm, which would roughly equate to 1 gpm. Therefore, small pressure boundary leaks (less than 1 gpm) might not be investigated in a timely manner. This was of concern because the TSs do not permit operation with any pressure boundary leakage, regardless of the magnitude. In response to this concern, the licensee created a program to formalize management of leakage monitoring and actions. This program was focused on leakage less than TS limits and was proceduralized in 0PGP03-ZO-0046, Revision 0.

The licensee has numerous radiation detectors inside the RCB which could detect the buildup of radioactivity as a result of a leak. The location, range, and purpose of these detectors vary. The UFSAR credits only the containment atmosphere radioactivity monitoring system (RT 8011) specifically for RCS leakage detection. RT 8011 obtains a sample of RCB atmosphere and uses particulate, iodine, and noble gas radiation monitors to detect elevated radioactivity in the RCB atmosphere. The TSs require only that the gaseous or particulate monitor be operable. This system design is also intended to meet the Regulatory Guide 1.45 recommendation of being capable of detecting an RCS leakage increase of 1 gpm within an hour. The system does not rely on the plant computer; it provides a control board alarm when a high radioactivity condition existed. The team verified that an annunciator response procedure was available; however, it did not provide an approximate relationship converting the signal to units of water flow to assist the operator in interpreting the monitor signals, as recommended in Regulatory Guide 1.45. Nevertheless, the response procedure did direct actions to investigate the alarm to determine if the increase in signal did reflect an increase in RCS leak rate and the selected alarm setpoint was intended to provide early indication of an RCS leak.

The team reviewed calculations supporting the design bases of the containment radioactivity monitoring system and identified a discrepancy. The UFSAR stated that the filter tape speed associated with the particulate monitor of RT 8011 was 1 inch/hour, and that is the actual filter tape speed of the as-built monitor in the plant. Additionally, the sample flow rate of the monitor is 2 cfm. However, the calculation documenting the capability of the particulate monitor to detect an increase in RCS leakage of 1 gpm within an hour was based on a filter tape speed of 0.5 inch/hour and a sample flow rate of 3 cfm. The team determined that the incorrect assumptions in the calculation produced a nonconservative result. Using the correct values in the calculation would challenge the conclusion that the monitor was capable of detecting an increase in RCS leakage of 1 gpm within an hour for high RCS activity conditions. The licensee initiated Condition Report 03-9961 in response to this finding and performed an operability determination which concluded that the system was operable. As a corrective action, the licensee revised its calculation of the particulate monitor's sensitivity and determined that it was capable of detecting a leak with the as-built parameters. Therefore, the error in the original calculation was a minor issue that is not subject to enforcement action in accordance with Section IV of the Enforcement Policy.

Instrumentation to measure containment humidity and temperature were available. No annunciators were available for these indications, as they were primarily intended as confirmatory indications to the primary leakage detection instruments. Both of the STP units have large dry RCBs maintained at 60-85 °F (depending on the elevation) with relative humidity typically 25 percent during operation. The large cooling capacity of the containment fan coolers made it unlikely that a small leak would result in a change in containment pressure or temperature. However, the coolers would condense and collect any increased humidity, delivering it to the sump for monitoring.

The UFSAR credits periodic manual RCS water inventory balance calculations to detect inter-system leakage. TSs require these to be performed at least every 72 hours, although the normal STP practice is to perform them daily. The accuracy of this calculation is between 0.1 and 0.2 gpm.

Ability to Detect RCS Pressure Boundary Leakage

All liquid leakage in containment could be collected in the sumps. However, leakage from sources that do not originate in the RCS are frequently present. Therefore, sump monitoring is only useful to identify changes in the amount of water collected in the sumps, as perceived by rotating crews of operators. This perception can be highly variable, but the licensee would typically investigate sump flow that had 2-3 alarms in a shift. Water inventory balance calculations provide the only quantification of leakage rates. However, the team noted that the licensee's procedures did not specifically address RCS pressure boundary leakage. The licensee's reactor coolant inventory calculation inappropriately assumes that all leakage that is not from known sources (identified leakage) is unidentified leakage as defined in the TSs. However, this does not prompt an evaluation to determine whether pressure boundary leakage existed. The team concluded that the daily calculation would assign any pressure boundary leakage to the unidentified leakage category. The licensee typically would investigate the source of unidentified leakage when it was consistently in the 0.3 to 0.4 gpm range.

To distinguish between RCS leakage and other leakage sources, the licensee would sample the contents of the containment sumps. If radioactivity levels increased or different isotopes than typical values were present, RCS leakage would be suspected. If nonradioactive contaminants were present or radioactivity was diluted, the source would be presumed to be not the RCS.

The licensee's ability to distinguish between unacceptable pressure boundary leakage and acceptable unidentified RCS leakage depended on the location of the leak. Fundamentally, pressure boundary leakage would not be assumed unless direct observation indicated this was likely. During plant operation, much of the RCS pressure boundary is inaccessible for inspection. Through discussions with licensee personnel and review of past performance, the licensee's decision to reduce power or shut down to identify the source of a leak was related to the magnitude and perceived potential operational impact of the leak.

The team concluded that the licensee's online leakage detection capabilities satisfied the current regulatory requirements, but those requirements and capabilities were incapable of detecting the small magnitude BMI penetration leak that existed in STP, Unit 1. However, the team also concluded that the combination of the licensee's BACC program walkdowns and the online RCS leakage detection capability would have been adequate to detect a BMI penetration leak well before it became a significant safety concern, permitting the licensee adequate time to complete an orderly shutdown in accordance with TS requirements.

2.3.2 Results and Effectiveness of Previous Inspections

a. Inspection Scope

The team reviewed documentation for the licensee's BACC walkdowns and ASME code pressure boundary inspections conducted throughout the life of both units. The team discussed the methods used to inspect, document, and assess observations with the system engineers who performed the inspections.

b. Observations

The team concluded that the BACC walkdowns of the RCS were performed in a consistent manner by a small group of system engineers who were properly trained and experienced. Their inspections were well documented. Recent inspection results included photographs, well-supported recommendations for addressing leaks identified, and condition reports initiated for resolving each issue. The team noted that nearly all leaks were identified and addressed in the same outage, and very few repeat problems occurred in subsequent outages.

For inspections of the RPV bottom head during refueling outages, the team noted that the licensee delayed inspecting this area until several days into the outage. The licensee stated that this was intended to allow the radiation dose rates in the room to decay in order to limit worker dose received during the inspection. As a result, this area was not inspected while the RCS was hot and pressurized as the rest of the areas were. While this had the potential to make leakage more difficult to identify in many portions of the plant, the team concluded that the impact was minimal in the RPV lower head area. This was because the inspector had to be very close to the area being examined and there was nothing to impede direct observation of the bare metal, such as insulation. However, the team noted that the licensee's method of inspection did not obtain a direct view of the full circumference of each BMI nozzle at the RPV surface. To observe the nozzles, insulation panels were opened below the reactor. This permitted observing the nozzles on the same side as the viewer and only the portions facing the viewer. There was no way to completely examine the back side (downhill side) of all nozzles without assistance. The licensee's original practice for accessing the RPV lower head had been to open two insulation panels 180 degrees apart (usually the same panels were opened each outage). During the previous outage in each unit, this practice had been improved to open three panels 120 degrees apart. Also, the licensee has changed its inspection procedure to require the removal of three panels. This improved the viewing coverage, although a small portion of the circumference of some nozzles was still not observable. The team concluded that this did not prevent the performance of an effective visual inspection.

The RPV under-vessel area is also required to be visually inspected for leakage in accordance with the ASME Code during system pressure testing at the end of an outage after plant heatup to normal operating temperature and pressure. The ASME Code, however, only requires the removal of insulation from bolted connections. The licensee performed this inspection using Procedure 0PSP15-RC-0001, "Reactor Coolant System Leakage Pressure Test," Revision 8. The team noted that, until the previous refueling outage in each unit, the licensee had been taking credit for the BACC walkdown inspections performed at the beginning of the outage in order to minimize radiation exposure. While this did not meet the ASME Code requirement since the plant was not at normal temperature and pressure, it did not result in failure to identify unacceptable leakage. The licensee had identified and corrected this issue. Therefore, it was a minor issue that is not subject to enforcement action in accordance with Section IV of the Enforcement Policy.

The team reviewed the method and results of the STP, Unit 1, RPV bottom head inspection conducted during a forced outage on November 20, 2002. The team concluded that the licensee performed the inspection properly and that there was no evidence of BMI penetration leakage.

2.3.3 Results of Current BMI BACC Inspection

a. Inspection Scope

The team reviewed documentation for the licensee's April 2003 BACC walkdown of the RPV bottom head area and discussed the walkdown methods with the system engineers who performed the inspections. The team reviewed the basis of the licensee's conclusion that the observed residue was due to RCS leakage, as well as the licensee's leakage estimates and efforts to estimate the age of the residue.

b. Observations

The team concluded that the licensee conducted an effective inspection and worked diligently to assess the source of the identified deposits. Appropriate actions were taken in accordance with TSs and other regulatory requirements when the licensee had enough information reasonably to conclude that RCS pressure boundary leakage had occurred.

The licensee had radio-chemical analyses performed on the deposits, both on site and at independent labs off site. These tests concluded that the residue was from RCS leakage that occurred with the plant at power. The presence of lithium and lack of visible trails down the reactor vessel eliminated the possibility that the source was a leaking refueling cavity seal. The licensee estimated the age of the deposits was between 3.5 and 4.5 years by comparing the ratios of the activity of isotopes present to their ratios in past samples of reactor coolant, correcting for the decay time. The team noted that there was not a formally recognized method to do this. However, the licensee had several industry peers review and agree with this method. The team concluded that the licensee's age determination method and result were reasonable.

The implication of having residue several years old which was not visible during prior inspections was examined. Since the team had confidence in the quality of the RPV lower head BACC inspections, the leaks must have been very small. This conclusion is supported by conservative estimates performed by the licensee and reviewed by the team. An estimate of the total quantity of leakage was that it was less than 50 gallons over the calculated 3.5 to 4.5 year period. The NDE inspections confirmed that the leaks resulted from very tight cracks.

2.4 Root Cause and Extent of Condition Evaluation

a. Inspection Scope

The team reviewed the licensee's root cause evaluation process, the information gathered by the licensee to support its preliminary root cause determination (including relevant operating experience), and the licensee's preliminary root cause determination to assess its completeness and accuracy.

b. Observations

Root Cause

The licensee's process for its root cause evaluation was integrated from the beginning with its evaluation of potential failure modes and effects associated with BMI penetration cracking. Given recent industry operating experience with RPV upper head penetration cracking and the general similarities between upper and lower RPV head penetration fabrication, the licensee began with a draft root cause/failure modes and effects analysis (FMEA) flow chart developed by the Electric Power Research Institute (EPRI) for RPV upper head penetration cracking. The principle focus of the EPRI flow chart was on PWSCC as the most likely mechanism for penetration degradation. This was consistent with the mechanism which had been observed to be actively degrading RPV upper head penetrations. The licensee, with assistance from industry experts, then expanded the EPRI flow chart to account for other degradation mechanisms which may have participated in the initiation or growth of the observed cracking, including flaws from initial fabrication and fatigue. The licensee's final flow chart also identified how initial fabrication processes and plant operation may have contributed to the mechanisms identified above.

The licensee's use of an initial root cause model based primarily on a PWSCC assumption was reasonable given the known susceptibility of Inconel Alloy 600/82/182 material to PWSCC in a PWR primary system environment. The team also concluded that the licensee appropriately expanded the scope of the root cause analysis to identify other known mechanisms, fabrication processes, and plant operating conditions which could have been reasonably expected to contribute to the observed degradation.

The licensee effectively incorporated the use of industry operating experience in its root cause determination efforts and in its selection of testing methods. The vendor selected in the inspection and repair process had extensive experience with inspection and repairs of RPV upper head penetration nozzles at other facilities and with the inspection of RPV lower head penetration nozzles at foreign reactors. Other nonconventional inspection techniques were investigated and employed as a result of review of international operating experience. These included, for example, a gas bubble test, which was demonstrated at a foreign reactor.

The details of the results of the licensee's preliminary root cause assessment are documented in their letter to the NRC dated July 11, 2003. In summary, the licensee's assessment concluded:

> The cracks that resulted in the leak paths most likely resulted from manufacturing (welding) flaws resulting in excessive stress in the nozzle/weld material leading to crack initiation with low cycle fatigue/primary water stress corrosion cracking supporting crack propagation.

In order to further investigate the potential root causes, the licensee obtained material samples from the leaking BMI penetrations for destructive evaluation. These samples included the bottom portions of Penetrations 1 and 46 removed from the RPV during the repair process and "boat samples" from the nozzle-to-J-groove weld interface inside of the RPV containing portions of flaws identified in the NDE inspections. However, the licensee informed the team that the boat sample obtained from Penetration 46 had been lost. At the time of this writing, the licensee had been unable to locate the sample. The licensee planned to complete a final root cause determination which included analysis of the material samples obtained and provide the results to the NRC in October 2003 in conjunction with a supplement to LER 05000498/2003-003.

The details of the NRC's review of the licensee's preliminary root cause assessment were documented in a Staff Evaluation forwarded to the licensee on July 31, 2003. The team concluded that the licensee's root cause assessment process was rigorous and thorough. However, the team concluded that insufficient information existed to judge the accuracy of the licensee's preliminary root cause determination. Instead, the team concluded that it was appropriate to reserve judgement on the results until the NRC has had opportunity to review the results of the material sample analyses. The team recommended to NRC management that this occur in conjunction with NRC staff review of the licensee's supplement to LER 05000498/2003-003. NRC management concurred with this recommendation. Follow-up review of the licensee's root cause determination will be conducted by review of the licensee's supplement to the LER. This did not affect, however, the team's conclusion that an effective repair design had been chosen and implemented which enveloped all probable root causes.

Extent of Condition

The team concluded the licensee's extent of condition evaluation was thorough and rigorous. All STP, Unit 1 BMI penetration nozzles and J-groove welds were inspected to determine if additional penetrations required repair or had cracks. Multiple inspection techniques were used on a smart sample of penetrations to obtain additional useful information regarding their condition. Exterior-vessel UT examinations of the leaking penetrations were performed to confirm that subsurface wastage did not exist.

The team concluded the licensee also effectively addressed extent of condition considerations with respect to STP, Unit 2. The licensee and team reviewed past RPV lower head BACC program inspection results. No adverse conditions had been identified. The licensee developed a plan for the prompt assessment of Unit 1 NDE inspection results to determine if there might be an immediate safety concern for Unit 2. Based on the inspection results, the licensee determined that no immediate safety concern existed for Unit 2 and the team concluded that this was an acceptable conclusion.

The future inspections, described in Section 2.7.2, that the licensee planned of STP, Unit 2, were considered by the team to be a reasonable approach to confirming the extent of condition, given the current Unit 1 NDE inspection results and past Unit 2 BMI BACC program inspection results.

2.5 Risk Assessment

a. Inspection Scope

The team reviewed the licensee's risk assessment of the BMI leakage issue and performed an independent qualitative risk assessment of the condition. To accomplish this, the team reviewed the failure modes and effects analyses and risk assessments, and conducted discussions with licensee engineering and risk assessment personnel. Additionally, the team reviewed the operational aspects of recovery from a bottom-head LOCA. Although the team concluded that a bottom-head LOCA was not a credible event based on the as-found condition, the team performed this review for completeness. The team observed plant and operator performance during simulator sessions which modeled the event. The team reviewed plant-specific and Westinghouse generic emergency operating procedures and emergency response guidelines. The team assessed available indications and procedural opportunities to diagnose the condition and implement critical manual actions.

b. Observations

Qualitative Risk Assessment

The team performed an independent qualitative assessment of the risk associated with the BMI penetration leakage issue and the results are summarized here:

The cracks identified in Penetrations 1 and 46 were axial in orientation and showed no tendency for becoming circumferential. Given this geometry, it is highly likely that further propagation would have resulted in an easily detectable and manageable leak before a larger and more risk-significant break would have occurred.

Based on the age of the boric acid deposits, the cracks were propagating at a very slow pace. Given the effectiveness of the licensee's BACC inspection program for the RPV lower head, it is likely that future opportunities to detect the leakage would have existed during subsequent refueling outages before a flowing-type leak occurred.

Although not deemed credible for the as-found BMI penetration cracks, based on the slow leak propagation and the effectiveness of licensee BACC program walkdowns, the worst-case break would have resulted in a flow area of 0.6 inches in diameter. Plant simulator demonstrations indicated that recovery from this event would have been easily handled by makeup systems after depressurizing the steam generators using currently proceduralized and practiced methods. Therefore, the conditional core damage probability would have been similar to the baseline for a small break LOCA. The licensee's probabilistic risk assessment (PRA) assigned a conditional core damage probability (CCDP) for a small break LOCA as 1.86E-4. The NRC's model (SPAR, Revision 3i) model gives a CCDP of 2.6E-4.

A smaller leakage scenario would have been identified by the RCS leakage detection system and would have resulted in a reactor shutdown to execute repairs. The risk for this condition would be similar to a standard transient. The licensee's PRA assigned a CCDP for a transient as 1.92E-7. The NRC's SPAR, Revision 3i, model gives a CCDP of 4.3E-7. Detection of leakage by the BACC walkdown program would have occurred during a plant shutdown, and would not have resulted in an additional transient.

Using the above figures and the qualitative assessment of the relative risk of a standard small break LOCA versus the scenario in question, the risk of a nozzle failure becomes important when the probability of the nozzle failure occurring before a leak or crack detection by inspection is 1/260 or higher (which gives an incremental CCDP of greater than 1.0E-6). Based on the crack orientations, propagation rate, and method and frequency of inspection, the probability that a break would have occurred first is likely several orders of magnitude below 1/260.

Based on this analysis, the team concluded that the risk associated with the condition was very low.

Plant response and operator recovery for BMI nozzle failure

The team concluded that a worst-case BMI nozzle failure was a small-break LOCA which was within the capacity of the emergency core cooling system (ECCS), provided operators implemented a procedurally-driven manual action.

The licensee concluded that the maximum break size involving a failed BMI nozzle would have a flow area of 0.6-inch diameter. This was equivalent to the inside diameter of the nozzle. The team agreed that a larger break size was not credible, given the observed degradation. The licensee performed an evaluation and simulator demonstration that the combined effects of this break size and RCS location were within the capability of the ECCS.

The team concluded that the licensee was not required by design and licensing requirements to have postulated or analyzed a break in this location. As discussed in the UFSAR, this was due to the high standards placed on fabrication methods and verifications performed during fabrication. However, a break in this location represented a more significant challenge than break locations previously analyzed. This was because a small break of this magnitude allowed RCS pressure to remain higher than the shutoff head of the high-head safety injection pumps. The STP design did not credit the nonsafety related charging pumps in the ECCS performance capability assessment of the LOCA analysis. Also, with the break location upstream of the fuel, any break flow would leave the RCS without providing core cooling.

From the very conservative standpoint of a deterministic analysis, satisfactory core cooling was assured only if operators took manual action to reduce RCS pressure sufficiently to allow high-head safety injection pumps to inject into the core. The team confirmed that this action was procedurally required in all small-break and medium-break LOCA scenarios. Operators were trained to take this action. The team also concluded that this action can be accomplished with high confidence in success. Critical safety function status changes would cause operators to implement actions to accomplish this action with a high priority if not otherwise accomplished. Further, the team concluded that there was adequate time to implement these actions before core damage occurred.

From a PRA standpoint, which represented more of a best-estimate case than the deterministic case, the licensee determined that adequate core cooling was available. The licensee's PRA model credited the charging pumps, which had a combined capacity that exceeded the postulated break flow. The team noted that the PRA model in use at the time of the inspection did not model the manual action to reduce RCS pressure to allow high-head safety injection pumps to inject, even though this action was necessary in a number of scenarios. The licensee was aware that this action was not modeled and intended to add it in the next revision to the PRA model.

The licensee modeled a 0.6-inch diameter break located at the reactor bottom head using the simulator and recorded plant performance and operator actions in response to the event using emergency operating procedures. The initiating event involved a sudden break while operating at full power in a normal lineup, except that one train of

ECCS equipment was disabled. This was more conservative than the PRA case above, since it included a worst-case single failure, but was less conservative than the deterministic analysis case above because charging pumps were available throughout the scenario. Two cases were run. One allowed operators their normal discretion to start the second charging pump in response to the leak, the second permitted them to start the second charging pump only when procedurally directed to do so. The difference between the cases was minor.

The simulator tests confirmed that to obtain adequate core cooling, operators were required to manually reduce RCS pressure sufficiently to allow ECCS injection. The availability of charging pumps provided more time to accomplish this action, but did not make it unnecessary. Charging pumps alone were capable of matching break flow initially, but depressurization and use of the greater flow rate available from the high-head safety injection pumps was necessary for long term cooling. The team concluded that the critical manual action could be reliably performed as a low-stress operator action.

2.6 NDE Activities and Results

2.6.1 NDE Techniques and Capabilities

a. Inspection Scope

The team observed demonstrations of NDE capabilities to assess whether the selected techniques were capable of accurately detecting and sizing flaws in the BMI penetration nozzles. The team also observed demonstrations of NDE capabilities to detect surface-breaking flaws in J-groove welds and wastage in an RPV. The team reviewed procedures for use of the chosen equipment and interviewed technicians and analysts.

b. Observations

The licensee and its vendors performed demonstrations of NDE capabilities on test mockups. The technologies being demonstrated for the BMI nozzle inspections were similar to those used in past industry inspections of CRDM nozzles, a similar but less challenging application. The intent of the nozzle inspection demonstrations was to address NDE equipment capability to detect, locate, characterize, and size flaws located on the ID or OD. Simulated flaws were placed in the test mockups. Flaws included axial and circumferential cracks and weld lack of fusion to the nozzle.

The nozzle inspection demonstrations were performed using test mockups where technicians knew locations of the simulated flaws (non-blind) and where technicians did not know the locations of the simulated flaws (blind). The non-blind demonstration was intended to enable the technicians to refine their processes for the expected plant conditions. The blind demonstration test allowed an objective and unbiased assessment of inspection capability. This test included flaw detection, flaw sizing location accuracy, and false positives.

The NDE technology used in the overall BMI inspection effort included:

- UT time-of-flight diffraction for detecting ID and OD flaws in the nozzles
- UT zero-degree focused probe for examining the fusion zone of the BMI nozzle to J-groove weld
- Eddy current testing (ET) for ID-breaking nozzle flaws
- Visual testing (VT) of the J-groove welds using high-magnification camera equipment
- ET of the J-groove weld crown for detecting surface breaking flaws
- ET profilometry of the nozzle ID to identify variations in the nozzle ID due to welding
- Helium gas pressure testing of BMI penetrations for the exterior of the RPV to identify leak paths to the interior of the RPV
- Phased-array UT on the exterior of the RPV lower head to detect low-alloy steel wastage

The team concluded that the licensee's NDE capabilities were acceptable and that the NDE technology used was capable of detecting and characterizing cracks in the BMI nozzles.

2.6.2 STP-1 Data Collection and Results

a. Inspection Scope

The team observed the acquisition and analysis of data from the BMI penetration inspections conducted onsite on STP, Unit 1. The team reviewed the data collection implementation procedures and reviewed the qualification records for the NDE analysts. The team also interviewed the analysts during the data acquisition and analysis phases. The team reviewed the results of the inspections and performed independent analyses of data to confirm the licensee's conclusions.

b. Observations

The results from BMI Penetration 1 are depicted in Figure 2. Three axially-oriented crack-like indications were identified in the nozzle wall. One of the indications was characterized as an axial crack with a length of about 1.38 inches, surface breaking on the OD of the nozzle above and below the J-groove weld, as well as surface breaking on the ID of the nozzle. The ID surface breaking nature of this flaw was confirmed by the ET examination. The OD surface breaking nature of this flaw was confirmed by the helium gas test. The other two indications were characterized as being small, embedded (i.e., non-surface breaking) cracks near the interface between the nozzle wall and the root pass of the J-groove weld.

The results from BMI Penetration 46 are depicted in Figure 3. Two axially-oriented crack-like indications were identified in the nozzle wall. One of the indications was characterized as an axial crack with a length of about 0.98 inches, surface breaking on the OD of the nozzle above and below the J-groove weld. The surface breaking nature of this flaw was unable to be confirmed by the helium gas test. The flaw was not found to be surface breaking on the ID of the nozzle by the ET examination. The other indication was characterized as an embedded crack having an axial length of 0.95 inches.

The UT examination capability was not demonstrated to be effective for the purpose of examining the subsurface volume of the J-groove weld. Therefore, the depictions of the indications shown in Figures 2 and 3 beyond the nozzle may be incomplete with respect to subsurface cracking of the J-groove weld.

No crack-like indications were identified in any of the other 56 BMI nozzles.

The results of the UT inspection did, however, identify other features within the BMI penetrations which were deemed to be relevant by the licensee. UT reflectors were observed and characterized as “anomalous conditions” or “discontinuities” at the interface of the nozzle and the J-groove weld in all of the STP, Unit 1, BMI penetrations. The licensee concluded that these discontinuities were potentially evidence of weld lack of fusion, porosity, or some other welding defects from original fabrication. These discontinuities were particularly evident in 7 penetrations, including Penetrations 1 and 46. The licensee also concluded that discontinuities in Penetrations 1 and 46 were located in the same general azimuthal locations as the crack-like indications.

The VT and ET examinations of the J-groove weld surfaces identified no surface cracking in any of the 58 BMI penetration J-groove welds.

The phased-array UT examination of the RPV around Penetrations 1 and 46 identified no wastage of the low-alloy steel base material. This was a potential concern due to exposure to borated RCS water from the leaks. Visual examination of the nozzle bores during the repair process also supported this conclusion.

Based on the team’s observation and review of the licensee’s BMI inspection campaign and independent analysis of data obtained, the team concluded that the licensee had accurately determined the condition of the STP, Unit 1, BMI penetrations. The team concluded that the licensee had correctly identified the two nozzles requiring repair which were the two leaking nozzles.

2.7 Prompt and Long-Term Corrective Actions

2.7.1 Prompt Corrective Actions

a. Inspection Scope

The team reviewed the licensee’s prompt corrective actions in response to the BMI leakage issue. The team reviewed the modification package which installed the BMI penetration repair and observed portions of its installation and inspection on BMI

Penetrations 1 and 46. The team also assisted in the NRC review of requests for relief from ASME Code requirements by performing some independent verifications of calculation design inputs and methods.

b. Observations

Upon the discovery of the deposits around STP, Unit 1, BMI Penetrations 1 and 46, the licensee began the process of designing a potential repair option. The licensee developed a “half-nozzle” repair which was similar in design to those which had been implemented at other facilities for the repair of cracked pressurizer heater penetrations, RCS instrumentation penetrations, etc. This repair option was chosen and characterized as a permanent repair of STP, Unit 1, BMI Penetrations 1 and 46. A cross-section of the repair design is shown in Figure 4. The essential elements of the repair design were as follows:

- The lower portion of the original Inconel Alloy 600 nozzle was cut off flush with the exterior surface of the RPV bottom head.

- An Inconel Alloy 52/152 (the weld wire equivalent of Inconel Alloy 690) temper bead weld pad was welded to the exterior surface of the RPV bottom head at the nozzle penetration.

- A J-groove weld prep was machined into the temper bead weld pad, and the remnant of the original nozzle which may interfere with the repair installation was bored out of the vessel to a depth of approximately 1.5 inches. Visual inspection of nozzle bores for evidence of low-alloy steel wastage was conducted.

- A new Inconel Alloy 690 nozzle was inserted into the penetration and welded to the temper bead weld pad by an Inconel Alloy 52/152 partial penetration J-groove weld.

The licensee’s repair design, therefore, moved the RCS pressure boundary to the exterior surface for the RPV bottom head at the location of the new Inconel Alloy 52/152 J-groove weld.

The licensee’s repair design also included a gap between the bottom of the original Inconel Alloy 600 nozzle and the new Inconel Alloy 690 replacement nozzle. This gap was necessary in order to permit thermal expansion of the nozzle halves without the potential for applying interference-related stresses to either the original J-groove weld or the new Inconel Alloy 52/152 J-groove weld. The existence of this gap creates an annular region between the original J-groove weld and the half-nozzle repair in which the low-alloy steel of the RPV bottom head is exposed to borated RCS water. The licensee analyzed the potential for boric acid corrosion of the low-alloy steel in this region. The licensee concluded that due to low oxygen levels in the reactor coolant (except during refueling outages, a condition which was also accounted for) and the stagnant conditions which are expected to exist within the annular region; corrosion of the low-alloy steel was predicted to be insignificant through the end of the unit’s current operating license with respect to affecting the structural or leakage integrity of the RCS pressure boundary.

Further, the licensee concluded that this half-nozzle repair design was acceptable in that it met all the applicable repair and replacement requirements of the ASME Code Editions and Addenda incorporated within the STP, Unit 1, licensing basis with the exception of the following for which the licensee requested NRC staff approval of relief from ASME Code requirements.

The licensee requested relief from ASME Code requirements to utilize Inconel Alloy 52/152 weld material as part of the repair. The Edition and Addenda of the ASME Code incorporated within the STP, Unit 1, licensing basis as applied to repair and replacement activities did not address the acceptability of Inconel Alloy 52/152 material. The licensee requested relief to apply ASME Code Cases 2142-1 and 2143-1 to enable the use of Inconel Alloy 52/152 material. The NRC staff approved the licensee's relief request.

The licensee also requested relief from ASME Code Section III requirements to utilize applicable provisions of ASME Code Case N-638 to support use of the temper bead welding process as part of the repair. The 1971 Edition through 1973 summer Addenda of ASME Code Section III is the construction code of record for STP, Unit 1. This Edition and Addenda of ASME Code Section III does not address the temper bead welding process and would instead require the licensee to perform a postweld heat treatment on the Alloy 52/152 weld pad. The NRC staff approved the licensee's relief request.

The licensee also requested relief from 1989 Edition ASME Code Section XI requirements (the Section XI ASME Code edition incorporated into the STP, Unit 1, licensing basis relative to inservice inspection) related to the need to perform successive re-examinations of flaws left in service in the region of the original J-groove welds. As part of the repair, the licensee moved the RCS pressure boundary to the exterior of the RPV bottom head and did not attempt to remove the original flaw indications found in the STP, Unit 1, BMI Penetration 1 and 46 nozzles (although parts of the flaws were in fact removed as part of the electrical discharge machining material sampling process). Further, the licensee's inspection techniques did not permit the inspection of the subsurface region of the original J-groove welds to ascertain whether any flaws within the welds were also being left as part of the repair. The licensee requested relief from the ASME Code Section XI re-inspection requirements based on two general considerations. First, the licensee performed a fatigue analysis which substantiated that even if the original J-groove welds were cracked, the flaws would not grow into the low-alloy steel material of the RPV bottom head and compromise the RCS pressure boundary. Second, the licensee noted that since the RCS pressure boundary of the half-nozzle repair moves to the exterior of the RPV bottom head, the original J-groove weld was no longer considered part of the RCS pressure boundary and the flaws left in service would, therefore, not require reinspection. The NRC staff approved the licensee's relief request.

Staff from the NRC's Office of Nuclear Reactor Regulation performed an audit at the Framatome, Inc., facility in Lynchburg, Virginia, to assess the mechanical stress and fatigue design calculations associated with the repair process. A summary of this audit and Staff Assessment was documented on August 8, 2003 (ADAMS Accession Number:

ML032200366). The staff concluded that the calculations were performed in an acceptable manner.

The team concluded that the licensee's prompt corrective actions to address the BMI penetration leakage were acceptable. The licensee developed and implemented an effective repair.

2.7.2 Long-Term Corrective Actions

a. <u>Inspection Scope</u>

The team reviewed the licensee's long-term corrective actions in response to the BMI leakage issue. The team reviewed the licensee's long term monitoring plan to inspect BMI penetrations on STP, Unit 1 and Unit 2.

b. <u>Observations</u>

Based on the results of the licensee's inspection, preliminary root cause evaluation, and repair of the STP, Unit 1, bottom head penetrations, the licensee plans several ongoing inspection and monitoring activities for both STP, Units 1 and 2, to support the continued operability of the units.

First, the licensee will continue to perform 100 percent bare metal visual examinations of the STP, Unit 1 and 2, RPV bottom heads as part of the BACC inspection program in a manner consistent with how the inspections were conducted for STP, Unit 1, in April 2003. This is not a change for either unit, only a continuation of the licensee's established program of performing such inspections during unit refueling outages and during unit forced outages if the unit has been in operation for more than three months, and the forced outage is scheduled to be 72 hours or greater in duration. The licensee's BACC inspection program was demonstrated to be effective with regard to finding very small boric acid leakage deposits. The licensee has concluded that its established program will be effective at finding evidence of future leakage, if any were to occur, prior to the development of degradation which significantly affects the structural integrity of either unit's RPV. The licensee has determined that this conclusion is valid for both the STP, Units 1 and 2, penetrations which maintain the original nozzle/J-groove weld configuration, as well as for the two repaired penetrations on the STP, Unit 1, RPV bottom head.

Second, the licensee plans to perform volumetric and enhanced visual examinations of the STP, Unit 1, penetrations at the next in-service inspection of the RPV, which is currently planned for 2008 or 2009. These inspections were demonstrated to be effective at finding and characterizing crack-like indications in the Inconel Alloy 600 nozzle material of BMI Penetrations 1 and 46.

Third, the licensee plans to perform ultrasonic examinations of the RPV base material around one of the two repaired BMI penetrations for the next two alternate refueling outages (i.e., 1RE13 and 1RE15) to confirm that there are no indications of RPV low-alloy steel wastage from RCS water in the annulus area of the repaired penetrations.

Finally, the licensee plans to perform volumetric inspections of all STP, Unit 2, BMI penetrations at the next refueling outage when the core barrel is planned to be removed. According to the licensee this is currently planned for refueling outage 2RE11 in 2005.

The team concluded that the licensee's long-term corrective actions to identify any future BMI penetration leaks in a timely manner and to monitor the repaired penetrations were acceptable.

2.8 Potential Generic Safety Concerns

a. Inspection Scope

Based on the information from the licensee's inspection and root cause evaluation efforts to date, the team evaluated the potential for the STP, Unit 1, operating experience to be indicative of a generic issue which may affect other U.S. licensees.

b. Observations

Based on information presented in prior sections of this inspection report, the team noted that the spectrum of potential root causes/contributing factors (i.e., PWSCC, fabrication-related defects, material surface cold working due to fabrication processes, fatigue, etc.) did not suggest that STP, Unit 1, is "unique" when compared with the majority of the U.S. PWR fleet. STP, Unit 1 operating conditions may make its BMI penetrations more susceptible to some of the aforementioned mechanisms (e.g., PWSCC); however, it may only require additional time for other licensees to experience similar degradation. Fabrication-related causes would be equally applicable to other licensees since, to the team's knowledge, the practices used in the fabrication of the STP, Unit 1, BMI nozzles were not significantly different from the practices used when other PWR RPVs were manufactured.

Therefore, at this time, the team recommends that the degradation at STP, Unit 1, be evaluated as being indicative of a potential generic issue for all PWRs. This recommendation may be modified should new information be presented in the licensee's final root cause report which supports the position that the STP, Unit 1, BMI penetrations are in some way "unique" when compared to those at other U.S. PWRs.

The NRC issued Information Notice 2003-11, "Leakage Found on Bottom-Mounted Instrumentation Nozzles," on August 13, 2003, to specifically inform the industry regarding the findings at STP, Unit 1. The Information Notice also stated that the NRC was in the process of evaluating what information regarding PWR RPV lower head penetrations may be needed for licensees to demonstrate that RCS pressure boundary integrity is maintained at each facility.

The NRC issued Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," on August 21, 2003. The Bulletin required that each licensee operating a PWR with BMI penetrations provide a description of its RPV lower head inspection program and plans for BMI penetration inspections.

3.0 Enforcement

The team evaluated the enforcement aspects of the BMI leakage issue and held discussions with staff and managers representing Region IV, the Office of Nuclear Reactor Regulation, and the Office of Enforcement. The NRC reached the following conclusions:

STP, Unit 1, TS 3.4.6.2.a states that no RCS pressure boundary leakage is permissible and STP, Unit 1, TS 3.4.10 states that the structural integrity of the ASME Boiler and Pressure Vessel Code Class 1, 2, and 3 components shall be maintained. The leakage identified from STP, Unit 1, BMI Penetrations 1 and 46 on April 12, 2003, was confirmed to be RCS pressure boundary leakage and also indicated that structural integrity was not maintained. Therefore, this was a condition prohibited by TSs 3.4.6.2.a and 3.4.10. Although this resulted in two violations of NRC requirements, the entry conditions for evaluation under the traditional enforcement program were not satisfied, in that, the violations did not have actual consequences (as defined in Section IV.A.5.c of the Enforcement Policy), impede the regulatory process, or result from willful acts. Additionally, this issue was evaluated under the reactor oversight process. The NRC concluded that the licensee's actions did not contribute to the degraded condition and, thus, no performance deficiency was identified. As discussed in a previous section of this report, a qualitative risk assessment was performed and determined that this was an issue of very low significance. The licensee's corrective actions were acceptable. Based on these facts, the NRC has decided to exercise enforcement discretion in accordance with Section VII.B.6 of the Enforcement Policy and will not take enforcement action for these violations.

4.0 Exit Meeting Summary

On July 28, 2003, the team presented the inspection results to Mr. J. Sheppard, President and Chief Executive Officer, and other members of his staff at a public exit meeting held in Bay City, Texas. At the exit meeting, the NRC informed the licensee that NRC management would complete a review regarding the acceptability of restart of STP, Unit 1, and would provide written notice of the decision. This notice was provided in a letter to the licensee, dated July 31, 2003. The letter also forwarded a Staff Evaluation, which documented the bases for the NRC's conclusion that restart of STP, Unit 1, and continued operation of STP, Unit 2, was acceptable with respect to the BMI issue.

BMI Guide Tube Penetration

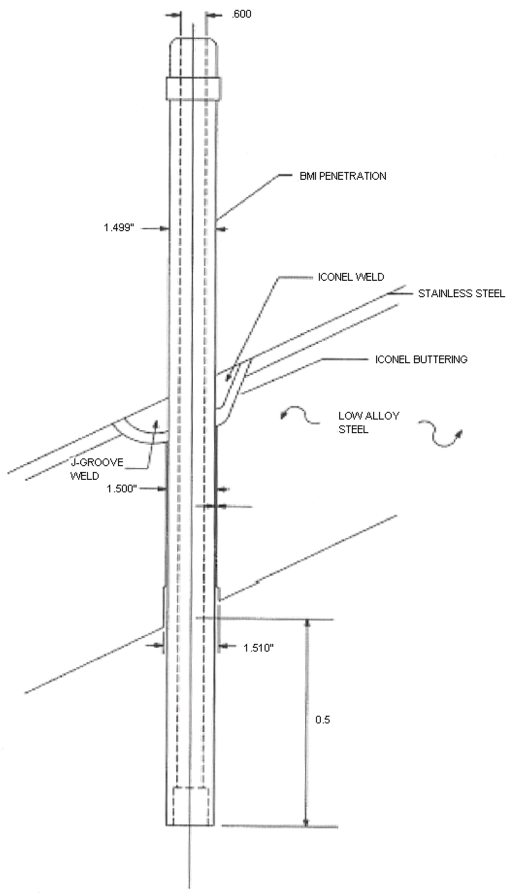

Figure 1

Penetration #1

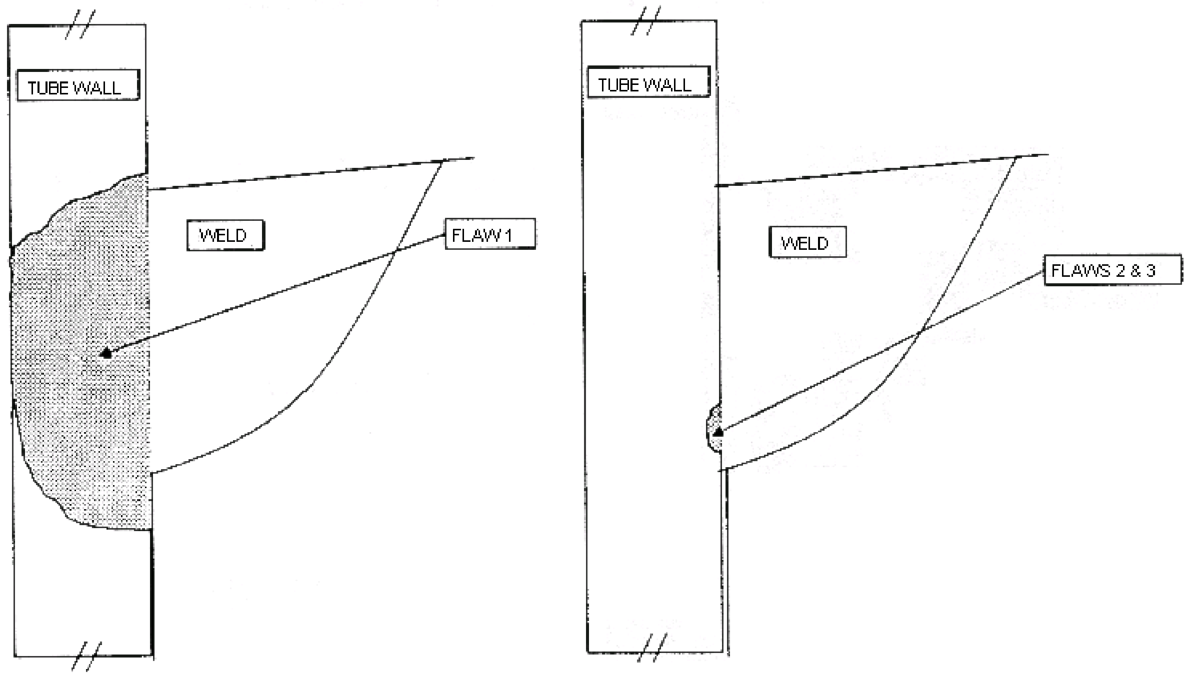

Figure 2

Penetration #46

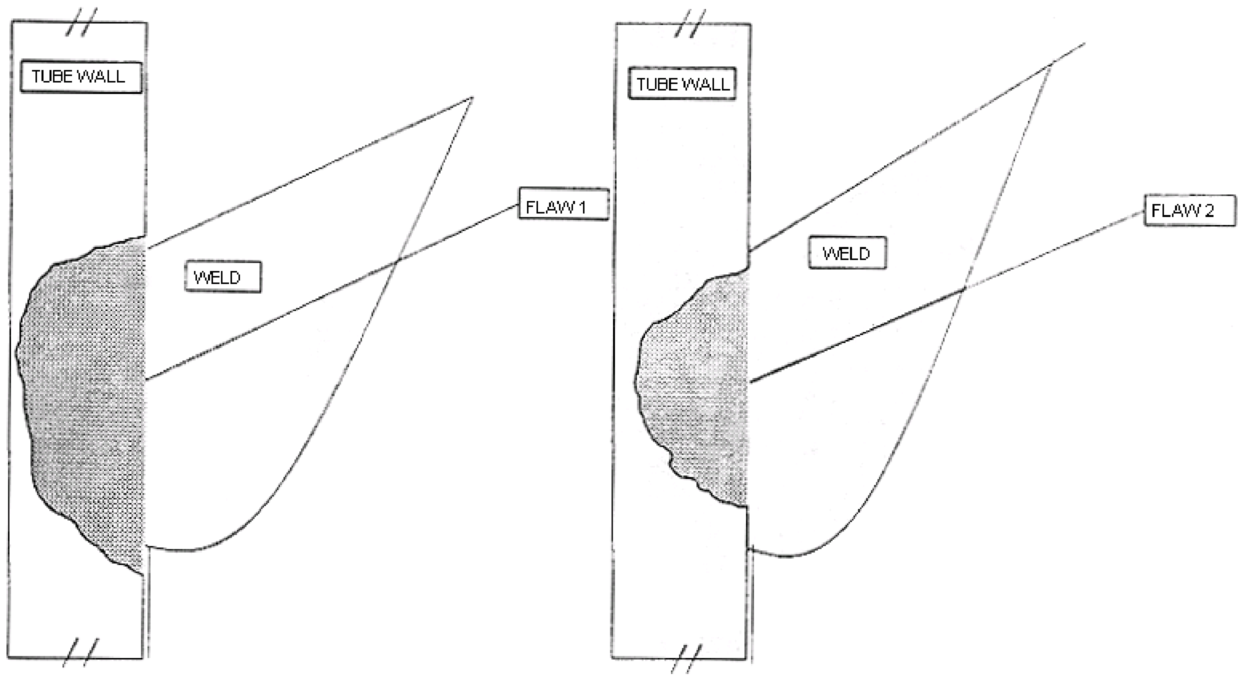

Figure 3

Half-Nozzle Repair

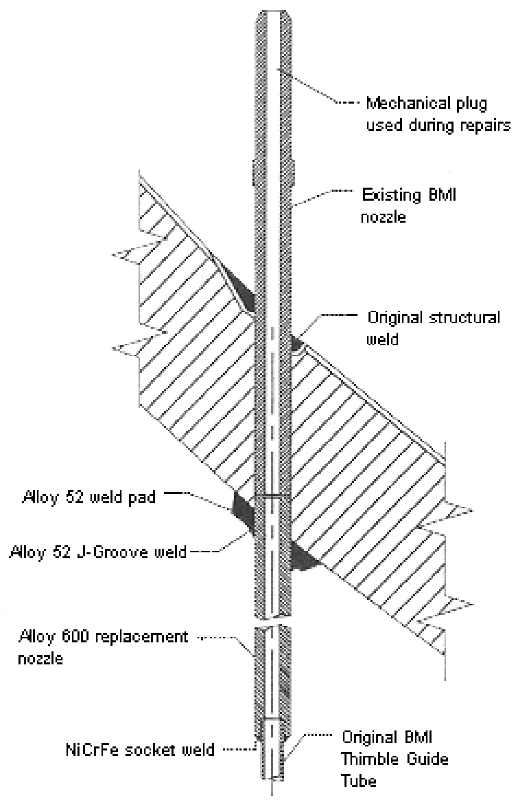

Figure 4

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

R. Dunn, Engineer, Risk Management
R. Gangluff, Manager, Chemistry
C. Grantom, Manager, Probabilistic Risk Assessment
E. Halpin, Manager, Plant General
W. Harrison, Senior Licensing Engineer
T. Jordan, Vice President, Engineering and Technical Services
M. Kanavos, Manager, Modifications and Design Basis Engineering
J. Langston, Acting Radiation Protection Manager
M. Lashley, Test Engineering Supervisor
M. McBurnett, Manager, Quality and Licensing
A. McIntyre, BMI Project Lead
W. Mookhoek, Senior Licensing Engineer
H. Murry, BMI Project Lead
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U. Patil, BMI Engineering Manager
J. Phelps, Manager, Operations Division
K. Richards, Director, Outage
D. Rencurrel, Manager, Operations
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R. Savage, Senior Staff Specialist
J. Sheppard, President and Chief Executive Officer
D. Stillwell, Supervisor, Configuration Control and Analysis
S. Thomas, Manager, Plant Design Engineering

NRC

W. Cullen, RES
R. Gramm, NRR
G. Guerra, RIV Resident Inspector
M. Hartzman, NRR
M. Thadani, NRR

LIST OF ITEMS OPENED AND CLOSED

None

LIST OF DOCUMENTS REVIEWED

Condition Reports:

93-0731
95-0973
96-2361
99-4411
02-13745
02-18174
02-18176
03-1958
03-6736
03-6768
03-9961

Procedures:

0PAP01-ZA-0104, “Plant Operations Review Committee,” Revision 1

0PSP15-RC-0001, “Reactor Coolant System Leakage Pressure Test,” Rev. 7 and 8

0PGP03-ZE-0023, “System Pressure Testing Program,” Rev.

0PGP03-ZA-0010, ”Performing and Verifying Station Activities,” Rev. 25

0POP01-ZA-0018, “Emergency Operating Procedures User’s Guide,” Rev. 16

0POP04-RC-0003, “Excessive RCS Leakage,” Rev. 10

0POP05-E0-E000, “Reactor Trip or Safety Injection,” Rev. 16

0POP05-E0-E010, “Loss of Reactor or Secondary Coolant,” Rev. 15

0POP05-E0-ES12, “Post-LOCA Cooldown and Depressurization,” Rev. 10

0POP05-E0-FRC2, "Response to Degraded Core Cooling,” Rev. 10

0POP05-E0-FRC2, "Response to Saturated Core Cooling,” Rev. 5

EOPT-03.07, “STPEGS Emergency Operating Procedures Technical Guidelines,” Rev. 15

0PGP03-ZE-0033, “Pressure Boundary Inspection for Boric Acid Leaks,” Rev. 7

0PEP10-ZA-0037, ”General Phased Array Ultrasonic Examination,” Rev. 0

OPSP03-RC-0006, “Reactor Coolant Inventory,” Revision 9

0POP04-RA-0001, “Radiation Monitoring System Alarm Response,” Revision 13

0POP04-RC-0003, “Excessive RCS Leakage,” Revision 10

0PSP03-ZQ-0028, “Operator Logs,” Revision 79

Planned Maintenance Instruction PMI-IC-II-1002, “Withdrawal/Insertion of Incore Flux Thimbles,” Revision 4

WO 391982, “Incore Nozzle Helium Leak Test,” Revision 1

Calculations:

C-33714-00-1, “South Texas Project BMI Nozzle Stress Analysis,” Revision 1

C-3714-00-05, “South Texas Project BMI Nozzle-Flaw Size Limits to Prevent Net Section Collapse,” Revision 0

03812-TR-02, “STP Flow Induced Vibration,” Revision 0

PRA-03-011, “Qualitative Risk Evaluation of Unit 1 BMI Leak Indications,” Revisions 0 and 1

“Evaluation of the Apparent Age of BMI Penetration Deposit Samples Collected at South Texas Unit 1 During 1RE11,” 2003

NC-9012, “Process and Effluent Radiation Monitor Set Points,” Revision 7

NC-9028, “RCS Leakage Detection by Particulate Monitor,” Revision 1

1C159RC7206, “Stress Analysis for RPV Bottom Mounted Instrument Tubing,” Revision 1

Framatome Engineering Information Record 5023945, “Simulation of IMI Nozzle Leakage of Reactor Coolant,” dated February 26, 2003

C-3714-00-6, “South Texas Project BMI Nozzle Gap Condition,” Revision 0

L-3713-00-1, “Qualitative Assessment of the Relative Susceptibility of the RPV Closure Head Nozzles at STP 1 and 2 to Primary Water Stress Corrosion Cracking in Comparison to the RPV Bottom Head Nozzles at STP 1 and 2,” Revision 0

Miscellaneous Documents:

South Texas Project Updated Final Safety Analysis Report

Licensee Event Report 05000498/2003-003-00, “Bottom Mounted Instrumentation Penetration Indications”

NRC Inspection Report 50-498/88-34; 50-499/88-34, June 21, 1988

NRC Inspection Report 50-498/89-42; 50-499/89-42, December 18, 1989

WCAP-16106, “Failure Modes and Effects Analysis for Bottom Mounted Instrumentation Penetrations, STP Nuclear Operating Company Units 1 and 2," versions May 2003 and June 2003

WCAP-16118, “PWSCC Assessment of the Alloy 600 Bottom-Mounted Instrument Tube Penetrations at South Texas Project Units 1 and 2,” version June 2003

South Texas Project Nuclear Operating Company, South Texas Unit 1, May 2003, Bottom Mounted Instrument Nozzle Inspection Final Report, Framatome ANP, June 25, 2003,

STP-1 BMI Nozzle Sample Test Plan, Revision July 3, 2003

STP-1 BMI Nozzle Lab Update, Revision July 21, 2003

BMI Visual Narrative Summary, Framatome ANP, 2003

Ultrasonic Technical Instruction Phased Array, Manual Ultrasonic Phased Array Examination at Reactor Head Penetrations, UTI-PA-001, Rev, 0, STI31615792, June 12, 2003

Eddy Current Bobbin Examination of STP STP BMI Nozzles, 51-5028703-00, Framatome ANP Engineering Information Record, May 30, 2003

Demonstration of Eddy Current Technique for Bobbin Examination of BMI Nozzles, 51-5028799-00, Framatome ANP Engineering Information Record, May 30, 2003

Eddy Current Array Examination of STP BMI Nozzles, 51-5028704-00, Framatome ANP Engineering Information Record, May 30, 2003

Demonstration of Eddy Current Technique for Array Probe Examination of BMI Nozzles, 51-5028799-00, Framatome ANP Engineering Information Record, May 30, 2003

Eddy Current Profilometry Examination of STP BMI Nozzles, 51-5029324-00, Framatome ANP Engineering Information Record, June 16, 2003

Design Change Package 03-6248-16, “Reactor Bottom Mounted Instrumentation Leak Repairs,” Revision 0

0105-0100105WN, “Vendor Technical Information for RCPCRV - Analytical Report for Unit 1 Reactor Vessel CENC-1302,” Revision B

STD-FP-1998-8202, “Vendor Technical Information for Flux Thimble D-12," Revision 0

Supplier Document E-255-1260, “Qualification Summary Report, STP 1 and 2,” Revision 6

Plant Impact Evaluation 94-12, “Intergranular Stress Corrosion Cracking in Control Rod Drive Mechanism Penetrations”

Plant Impact Evaluation 96-20, “Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Penetrations”

Framatome Engineering Information Record 51-5029324-00, “Eddy Current Profilometry Examination of STP BMI Nozzles,” dated June 16, 2003

Combustion Engineering Nuclear Fabrication Practice 101-3-0, “Tack Weld and Welding Practice for Instrumentation Tubes to PWR Bottom Heads,” May 3, 1976

LIST OF ACRONYMS

ASME	American Society of Mechanical Engineers
BACC	boric acid corrosion control
BMI	bottom-mounted instrumentation
cfm	cubic feet per minute
CRDM	control rod drive mechanism
CCDP	conditional core damage probability
ECCS	emergency core cooling system
ET	eddy current testing
EPRI	Electric Power Research Institute
FMEA	failure modes and effects analysis
gpm	gallons per minute
ID	inside diameter
LER	Licensee Event Report
LOCA	loss-of-coolant accident
NDE	nondestructive examination
OD	outside diameter
PARS	Publicly Available Records System
PRA	probabilistic risk assessment
PT	liquid penetrant
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
RCB	reactor containment building
RCS	reactor coolant system
RPV	reactor pressure vessel
SDP	Significance Determination Process
TS	Technical Specifications
UT	ultrasonic testinb
UFSAR	Updated Final Safety Analysis Report
VT	visual testing