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SUBJECT: Submits response to question from 970502 fax re Unit 1 JCO. Answers to addl questions will be provides in separate submittal.

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CATEGORY 1 DOCUMENT

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DUKE POWER

May 7, 1997

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

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -278
Justification For Continued Operation (JCO) of Oconee Unit 1 Based on Oconee Unit 2 HPI Line Leak, Supplement #2
NRC TAC No. M98454

As a result of a leak in the Reactor Coolant System (RCS), Oconee Unit 2 was shut down on April 22, 1997. The leak was caused by a crack in the weld for the pipe to safe end connection at the RCS nozzle for the High Pressure Injection (HPI) System A1 injection line. Duke Power immediately began investigating the cause of the leak. A JCO was submitted for Oconee Units 1 and 3 on April 28, 1997. As the investigation progressed, a review of past inspection data was completed on May 2, 1997 which indicated that one of the HPI thermal sleeves on Unit 3 was loose.

On May 2, 1997, Oconee management decided to shut down Oconee Unit 3. A revised JCO for Oconee Unit 1 was faxed to the staff on May 2, 1997. On May 2, 1997, the staff faxed Oconee several questions related to the Unit 2 HPI line weld crack and the Unit 1 JCO. A supplement to the Unit 1 JCO, dated May 3, 1997, was faxed to the staff to provide additional information regarding additional leakage detection measures implemented on Oconee Unit 1.

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Attached please find responses to the other questions from the May 2, 1997 staff fax related to the Unit 1 JCO. Answers to the remaining questions will be provided to the staff in a separate submittal.

Also, based on additional information from the ongoing investigation, Duke Power would like to clarify two aspects of the May 2, 1997 Unit 1 JCO. First, the May 2, 1997, JCO

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states that it appeared the augmented RT inspection program for Unit 1 was appropriately followed. This statement was made based on the information available at that time. Although not specifically documented in NRC correspondence, internal correspondence does define the augmented inspection program for Oconee Unit 1. The internal correspondence which defines the augmented inspection program for Oconee Unit 1 as it relates to Generic Letter 85-20 has been reviewed. This review determined that the committed inspections were performed until 1995, when RTs scheduled for Unit 1 were inappropriately included with other ISI items and deferred until the 1997 refueling outage.

Secondly, the May 2, 1997, JCO states that turbulent penetration of the thermal sleeves can be prevented by increasing letdown flow on Oconee Unit 1 to 105 gpm. The general guidance provided to Operations is that increasing letdown flow is beneficial in reducing the potential for thermal cycles on the normal injection nozzles. Currently, Operations has increased letdown to lessen the impact of turbulent penetration. Until further information regarding the thermal fatigue failure is analyzed, future practices will be to maintain letdown flow as high as can be safely achieved within the constraints and operating limits of the system. The intent of this guidance is to take the additional precautionary steps associated with good engineering practice to minimize the potential for thermal cycles on the nozzles.

In addition, during a May 2, 1997, conference call, the staff requested that Oconee provide its plans for inspections on Unit 3 and the potential impact of these inspection results on the continued operation of Unit 1. The scope of HPI line inspections on Unit 3 will include radiography of the thermal sleeve to safe end rolled joint, radiography of the safe end /piping weld and the safe end/nozzle weld, and ultrasonic testing of piping /welds from the outlet of the first HPI valve off the RCS to the nozzle joint area on the RCS piping. Video inspection of the thermal sleeve will also be performed on all four Unit 3 HPI System injection lines. The Unit 3 inspections were initiated on May 7, 1997.

The chronology of these inspections will be based on system conditions and the specific type of inspection being done. We intend to UT the thermal sleeves and some other piping/welds before the RCS is drained below nozzle level. Radiographic inspections will require the HPI lines and nozzles to be drained. Based on currently available data, it is Duke's belief that significant indications of thermal

fatigue will not be present in the HPI piping if the thermal sleeves are intact and properly attached. Thus, if these tests identify indications of significant thermal fatigue on injection lines with intact, properly attached thermal sleeves, we would begin an orderly shutdown of Unit 1. Significant thermal fatigue would be characterized as indications similar to those seen on the 2A1 piping/welds that are reportable under code requirements. Ultrasonic testing of the normal injection safe ends and welds of the safe end to the pipe and nozzle would be performed on Unit 1 to determine if any indications of thermal fatigue are present. Again, this approach is based on data that shows significant thermal fatigue indications have not been evidenced in upstream piping where the thermal sleeves are intact and attached properly.

If radiography or video results show a damaged or loose Unit 3 thermal sleeve (other than 3A1), we would initiate an orderly shutdown of Unit 1, since radiography data shows no detrimental gaps as of November 1996, and Unit 3 has operated only 1.5 months since that time.

In any event, given the time since the last NDE of the Unit 1 sleeves, we will begin an orderly shutdown of Unit 1 for UT of the two normal injection lines, as described above, as soon as Units 2 and 3 are operating at steady state power conditions.

In summary, Duke Power believes the continued safe operation of Oconee Unit 1 is justified based on the following:

- Administrative controls are in place to minimize thermal cycles introduced by variations in makeup flow.
- The Unit 1 thermal sleeves are of a different design than the Units 2 and 3 thermal sleeves and, based on a review of past inspection data, there is no indication any of the Unit 1 sleeves are loose.
- Enhanced leakage detection measures have been implemented by Oconee Operations as described in the May 3, 1997 submittal to the staff.
- Leak before break analyses demonstrate that there is a high level of confidence the plant can be safely shut down in the unlikely event a leak develops on Unit 1.

The information contained in this submittal reflects the technical judgment of the Oconee staff based on the current

status of the ongoing investigation of the Oconee Unit 2 leak. As new information becomes available, Oconee will continue to communicate its findings to the staff in a timely manner.

Please address any questions to J. E. Burchfield, Jr. at (864) 885-3292.

Very Truly Yours,

J. W. Hampton

J. W. Hampton
Site Vice President

xc: L. A. Reyes, Region II
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Attachment 1
Response to NRC Questions on Oconee Unit 1 JCO

On May 2, 1997, the NRC requested additional information regarding the crack in the pipe to safe end weld in the Unit 2 A1 HPI line. The staff faxed eight questions to Oconee, some of which contained multiple parts. The questions related to the Oconee Unit 1 JCO are 1.b,f,g, 2.a,c,e, 4.a,b,c,d,e,f, 6.a,b,c, 7.a,b,c, and 8.a,b. Responses to these questions are provided below.

Question 1b:

Provide the operational history for the normal charging/HPI injection system piping. State under what plant conditions is normal charging reduced or stopped (i.e., heating up, RCS leakage testing, when load following, etc.). State if there are any other conditions where all cooling, both normal charging and flow to the warming line, can be lost. Provide an estimate how often these events occur. Also, provide an estimate how often cold water is injected into a hot reactor (e.g., spurious safety injection signals).

Response:

Makeup flow for steady state 100% operation is routinely present and varies from 40 to 35 gpm. Power reductions and increases due to performance testing or load following is accomplished at a controlled rate, normally at < 3%/hr. Makeup flow varies during power changes. HPI pump testing, done quarterly, varies letdown flow which in turn results in cycling makeup flow approximately 4 times for each test. Unit startup results in approximately 8 cycles of makeup flow while power is increasing. Unit shutdown results in approximately 12 cycles of makeup flow while power is decreasing. Warming line flows bypass the normal makeup flow line, and are present even with normal makeup flow stopped. Warming line flows are present as long as HPI pumps are on. In the May 2, 1997 JCO, Oconee indicated that there have been 19 thermal cycles associated with emergency injection.

Question 1f:

Provide a detailed explanation of the relationship between the gap or gaps in the thermal sleeve and cracking of the pipe / safe-end weld. Discuss the potential for cracking of this weld with the thermal sleeve in place as well as out of position. Explain why cracking of the pipe / safe-end weld should not be expected if the thermal sleeve is installed and in place per design.

Response:

References:

1. B&W Owner's Group Report # 77-1140611-00, " 177 Fuel Assembly Owner's Group Safe End Task Force Report on Generic Investigation of HPI/MU Nozzle Component Cracking.

2. Letter from Toledo Edison Company to the United States Nuclear Regulatory Commission, Docket No. 50-346, License No. NPF-3, Serial Number 1580, dated September 14, 1988, "High Pressure Injection/Makeup Nozzle Thermal Sleeve."

In all cases where reactor coolant boundary leakage has occurred, there have been significant gaps between the thermal sleeves and the safe-ends. This occurred for both the leak at Crystal River in 1982 (Ref. 1) and the recent leak at Oconee Unit 2. In both incidences, cracking at the safe end to pipe weld was attributed primarily to thermal fatigue cracking induced by thermal cycling in the piping outboard of the safe end. The thermal sleeve damage noted at Davis Besse (Ref. 2) was also due to thermal fatigue accentuated by flow induced vibration. The principal difference between the Davis Besse event and the Crystal River/Oconee Unit 2 events is that the thermal sleeve at Davis Besse, while damaged, did not display gaps between the sleeve and the safe end at the rolled-in section.

There are three possible thermal hydraulic modes of operation that can lead to thermal fatigue cracking of the thermal sleeve, safe end, and safe end to pipe weld. All of these modes involve hot RCS fluid moving or back flowing toward the nozzle safe end.

The first mode is normal makeup at a low flow rate entering the thermal sleeve region. In this scenario, reduced make-up flow allows RCS fluid to overcome the dedicated bypass line flow and result in a turbulent mixing region that changes in location from the thermal sleeve to the warming line piping nozzle. During testing at Crystal River for a thermal sleeve tightly rolled into the nozzle, it was shown that a flow rate of 1.6 gpm was sufficient to prevent back leakage from entering the nozzle (Ref. 1). The bypass line flow at Oconee exceeds the minimum bypass flow specified in Reference 1.

The second mode is leakage past the thermal sleeve due to an open gap in the rolled end region of the thermal sleeve to the safe end. If there is a gap at this location, there is a secondary path for water to enter the safe-end/piping region from the reactor coolant piping. In this case, flow from the reactor coolant piping, that has a velocity pressure of about 10 psi,

impinges on the portion of the sleeve extending into the flow. This tends to increase the static pressure at the upstream side of the protruding thermal sleeve, causing a flow of hot reactor coolant to enter the thermal sleeve annulus. The pressure on the downstream side of the annulus and within the thermal sleeve are at a lower pressure, both being at the local static pressure of the flowing fluid. Thus, if there is a gap at the rolled end section of the thermal sleeve, the hot RCS fluid will flow through this gap into the region of the safe end to pipe weld. For relatively low flow rates in the piping region, the flow may stratify with the hot water filling the upper portion of the piping. The region at the weld is especially affected since it is close to the upstream end of the thermal sleeve. For higher flow rates, the cold flow may be sufficient to not allow the hot water to enter the upstream region. With varying flow rate, there will be thermal cycling. Open gaps in the rolled region of the thermal sleeve to the safe end also seem to be a common denominator to cracks in the safe end and the pipe to safe end weld.

The third case is postulation of cross flow from one RCS cold leg through a leaking HPI check valve to the other RCS cold leg. The normal makeup flow at Oconee is routed to two nozzles simultaneously. Each of the makeup nozzles are supplied with a dedicated bypass flow of 3 gpm. Assuming a letdown flow of 60 gpm, normal makeup flow to each nozzle is 17 gpm, or a total nominal flow to each nozzle of 20 gpm. Thermal stratification monitoring data taken in 1990 indicates that there may be some slight variation of the pressure between reactor coolant loops that, with time, could cause the flow split between the two nozzles to vary. This would occur at low flow during one or three pump operation when there would be a significant loop-to-loop pressure differential.

Past operation at Oconee indicates there have been periods when hot RCS fluid entered the nozzle. During startup, reactor coolant expansion leads to a significant reduction of makeup flow, possibly resulting in only warming line flow entering the piping. There are also periods when there is no flow in one of the reactor coolant loops, leading to increased static pressure in the loop without flow. Even though there is nominally enough warming line flow to keep the thermal sleeve full of cold water, back leakage through the adjacent check valves could potentially allow the flow rate of water in the thermal sleeve to decrease. This allows hot water to enter the piping for some short time. This also causes a transient on the inside surface of the cold thermal sleeve at the hard roll, which may contribute to relaxation of the hard roll, contributing to creation of a gap. It is judged that the number of cycles for this transient, and

the operating time in this condition, is not sufficient by itself to produce significant fatigue damage.

Another factor that could contribute to cracking in the safe end and the pipe to safe end weld is damage to the thermal sleeve. If a portion of the end of the thermal sleeve is missing, there could be additional fluid-dynamic and turbulence forces in both the annulus and within the thermal sleeve that could force hot water into the region upstream of the safe-end at flow rates higher than the nominal bypass line flow rate. This could tend to increase the rate of thermal cycling and produce faster fatigue damage and/or crack growth for the weld region.

Additional damage to the thermal sleeve after loosening by thermal cycling can be attributed to vibrational loadings from reactor coolant pump vane passing pressure pulsations, and from flow induced loadings, such as vortex shedding.

In conclusion, some thermal fatigue could occur in the region upstream of an intact thermal sleeve. However, based on the information available at this time, it is Duke's belief that significant thermal fatigue damage will occur only when the thermal sleeve is loose and allows backflow through the gap. Thus, it is concluded that there will be insignificant fatigue challenge to the piping and safe end upstream of the thermal sleeve, as long as the thermal sleeve is in place.

Question 1g:

Provide a detailed explanation of the benefit of using a dual thermal sleeve, as stated in the JCO, in preventing cracking similar to that found in the pipe/ safe-end weld in Unit 2.

Response:

Reference:

1. B&W Owner's Group Report # 77-1140611-00, "177 Fuel Assembly Owner's Group Safe End Task Force Report on Generic Investigation of HPI/MU Nozzle Component Cracking."

The dual thermal sleeve in Unit 1 was installed during initial construction so the length of the thermal sleeve would be sufficient to extend into the reactor coolant flow to prevent cold water impingement on the reactor coolant loop piping. [Ref. 1] In the original installation, the thermal sleeve was identical to the original design that failed at Crystal River and at Oconee Unit 2, except for length. Due to related industry experience, a slightly smaller and longer thermal sleeve was

rolled into the inside of the original sleeve. At the upstream end, there was a collar to prevent axial movement relative to the original thermal sleeve. This design has several advantages over the original thermal sleeve.

The inside diameter of the thermal sleeve for the original design (and all other B&W plants) is 1.50 inches. For the additional inner thermal sleeve, the nominal inside diameter is 1.235 inches. This results in an area that is approximately 68 percent of the unmodified design. For a specific flow rate, the Richardson Number (an indicator of tendency for stratified flow to exist) would decrease by a factor of 2.6. Thus, there will be less of a tendency to allow hot flow back into the piping/safe-end region as compared to Units 2 and 3.

Reasons why the tolerance to cracking for the dual sleeve is greater than a single thickness thermal sleeve are as follows:

- In the region of the roll, the inner sleeve will act as a partial thermal barrier to prevent heating of the outer sleeve for any hot water intrusions into the sleeve. This will assist in preventing yielding of the outer thermal sleeve material that might contribute to opening of the outer thermal sleeve-to-safe end gap.

- For any cold thermal shocks (upon increase of flow), the outside of the inner thermal sleeve will be protected from the reactor coolant high temperatures on the outside surface (by the outer thermal sleeve), resulting in lower thermal stresses. Likewise, the outer thermal sleeve will be protected from thermal transients by the inner thermal sleeve.

- The outboard end of the inner sleeve has a collar that is slotted at four locations over the original weld beads that retain the outer sleeve. In the event of any loosening, the flow path in the annulus past the hard roll area would be more tortuous, resulting in lower back leakage flows. In addition, the slots will prevent any rotation of the inner sleeve, and significantly reduce the potential for rotation of the outer sleeve. Thus, there will be much less potential for wear that would tend to increase the size of leakage gaps.

The dual thermal sleeve should be more resistant to cracking and provide better protection against hot water entering the upsteam piping region as compared to the single thermal sleeves at Units 2 and 3. This is substantiated by the fact that the geometry, as

measured by the latest radiographic inspections, has remained stable since the original construction.

Question 2a:

Provide a history of all examinations (volumetric, surface and visual) of the pipe/safe-end weld and adjacent piping and of the radiographic examination of the thermal sleeves in each unit of Oconee.

Response:

The requested information for Unit 1 is provided in Table 1. The information for Units 2 and 3 will be provided in a separate submittal. In addition, Rover video inspections of the Unit 1 nozzles were performed in 1991 and indicated that the thermal sleeves were intact.

Question 2c:

Identify the method used to perform the volumetric examination, the scope of the examination, the qualification procedure for determining whether cracks exist in the inspected material, and the results of the inspection. Describe any mockups that were used to qualify the UT inspection methods, including how representative the geometry and materials of the joint are represented by the mockup and the type of reflector e.g., EDM notch, fatigue crack, etc., were used.

Response:

Oconee Unit 1

The A1 and A2 high pressure injection nozzle safe ends on Oconee Unit 1 were inspected on January 18, 1989 using Babcock & Wilcox Procedure ISI-120. This procedure was written in compliance with the 1980 Edition of ASME Section XI with addenda through Winter 1980. The examinations were performed by two qualified Level II UT inspectors.

The calibration for axial scanning was performed using calibration standard 40416. The transducer selected for axial scanning was a single element, 45 degree refracted shear wave unit. The sensitivity was established by setting the peak response from the 1/2T side drilled hole at 80% of full screen height, which produced amplitudes of 60% full screen height from the 3/4T hole and 20% full screen height from the 5/4T hole. The

10% ID notch amplitude exceeded the DAC curve, so no gain adjustment was made. This was defined as the reference level for the axial scan. Sensitivity was then increased another 6dB to 14dB (depending on material noise) for scanning.

The calibration for circumferential scanning was performed using calibration standard 40416. The transducer selected for circumferential scanning was a single element, 45 degree refracted shear wave unit. The sensitivity was established by setting the peak response from the 1/2T side drilled hole at 80% of full screen height, which produced amplitudes of 58% full screen height from the 3/4T hole and 24% full screen height from the 5/4T hole. The 10% ID notch amplitude exceeded the DAC curve, so no gain adjustment was made. This was defined as the reference level for the axial scan. Sensitivity was then increased another 6dB to 14dB (depending on material noise) for scanning.

Procedure ISI-120 was qualified under the requirements of ASME Section XI, 1980 Edition with addenda through Winter 1980. This Edition did not require a performance demonstration for procedure or personnel qualification.

Oconee Unit 2

The A1, A2, and B2 high pressure injection nozzle safe ends on Oconee Unit 2 were inspected on April 2, 1996 using Procedure NDE-610. This procedure was written in compliance with Appendix 1 of the 1989 Edition of ASME Section XI with no addenda. The examinations were performed by a qualified Level III UT inspector assisted by a Level I UT inspector.

The calibration for axial scanning was performed using calibration standard 40343. The transducer selected for axial scanning was a dual element, 45 degree refracted longitudinal wave unit. The sensitivity was established by setting the peak response from the 1/2T side drilled hole at 80% of full screen height, which produced amplitudes of 65% full screen height from the 1/4T hole and 75% full screen height from the 3/4T hole. Sensitivity was then increased by 4dB to bring the 10% ID notch up to 75% of full screen height. This was defined as the reference level for the axial scan. Sensitivity was then increased another 6 dB for scanning. Under Procedure NDE-610, scanning sensitivity is normally set at 14 dB above reference level unless the ID surface noise level exceeds 1/3 of the lowest point on the DAC curve, in this case 25% of full screen height, in which case the sensitivity is reduced to bring the noise level below 1/3 of the amplitude of the lowest DAC point (but not below reference level).

The calibration for circumferential scanning was performed using calibration standard 40343. The transducer selected for circumferential scanning was a single element, 30 degree refracted shear wave unit. The sensitivity was established by setting the peak response from the 10% ID notch at 80% of full screen height. This was defined as the reference level for the axial scan. Sensitivity was then increased another 6.5 dB for scanning. Under Procedure NDE-610, scanning sensitivity is normally set at 14 dB above reference level unless the ID surface noise level exceeds 1/3 of the lowest point on the DAC curve, in this case 25% of full screen height, in which case the sensitivity is reduced to bring the noise level below 1/3 of the amplitude of the lowest DAC point (but not below reference level).

Procedure NDE-610 was qualified under the requirements of ASME Section XI, 1989 Edition. This Edition did not require a performance demonstration for procedure or personnel qualification. The technique used to inspect the nozzle safe ends on April 2, 1996 was very similar to that used under Procedure NDE-600 for the examination of the Unit 3 safe ends.

Oconee Unit 3

The A1 and A2 high pressure injection nozzle safe ends on Oconee Unit 3 were inspected on October 21, 1996 using Procedure NDE-600. This procedure was written in compliance with Appendix VIII of the 1992 Edition of ASME Section XI with addenda through 1993. The examinations were performed by a Level II UT inspector, qualified under Appendix VIII at the EPRI NDE Center through the PDI program.

The calibration for axial scanning was performed using a stainless steel reference block. The transducers selected for axial scanning were a dual element, 60 degree refracted longitudinal wave unit and a single element 60 degree refracted shear wave unit. The sensitivity for each transducer was established by setting the ID noise level from the nozzle being examined at an amplitude of 5% to 10% of full screen height. This was defined as the reference level for the axial scan. Scanning was performed at this sensitivity level.

The calibration for circumferential scanning was performed using a stainless steel reference block. The transducer selected for circumferential scanning was a single element, 30 degree refracted shear wave unit. The sensitivity was established by setting the ID noise level from the nozzle being examined at an amplitude of 5% to 10% of full screen height. This was defined

as the reference level for the axial scan. Scanning was performed at this sensitivity level.

Procedure NDE-610 was qualified in accordance with the requirements of ASME Section XI Appendix VIII. A performance demonstration was conducted by the EPRI NDE Center under the Performance Demonstration Initiative program. This performance demonstration was designed to verify the ability of the procedure to reliably detect flaws in samples representative of field conditions within the scope of the procedure. Each inspector using this procedure also completed a performance demonstration at the EPRI NDE Center, verifying his ability to properly implement the procedure. The performance demonstration consisted of scanning samples containing flaws including thermal fatigue, mechanical fatigue, and intergranular stress corrosion cracks, as well as interfering conditions such as ID counterbore, root geometry, OD weld crown, and single direction access. Flaws in both the axial and circumferential directions were included in the performance demonstrations for the procedure and each individual inspector.

Appendix VIII was written to provide assurance that flaws with dimensions (a combination of length and through-wall extent) in excess of the allowable sizes in ASME Section XI Table IWB-3514-1 and Table IWB-3514-2 were reliably detected. For the HPI nozzle safe end configuration, this is a flaw approximately 12.5% in through-wall extent and a length twice this dimension.

Comparison of Calibration Standards:

Two different calibration standards have been used for ultrasonic inspection of the high pressure injection safe ends at Oconee. The ultrasonic responses of the reflectors in both blocks were compared using the same equipment that was used in the 1996 Oconee 2 inspection. In the axial direction, the maximum difference in response was less than 1 dB. In the circumferential direction, the ultrasonic response of the ID notch in calibration block 40343 is approximately 3dB more sensitive than the ultrasonic response of the ID notch in calibration standard 40416. Calibration standard 40416 matches the installed safe end diameter, thickness, and material specification, so calibration using either standard provides proper sensitivity for an ASME Section XI inspection.

The ultrasonic responses of the reflectors in both blocks were also compared using the equipment comparable to that used in the 1989 Oconee 1 inspection. . In the axial direction, the difference in response was less than 2 dB, with calibration standard 40343 producing the highest sensitivity. In the circumferential direction, the difference in response was less

than 4 dB, with calibration standard 40343 again producing the highest sensitivity.

Conclusion:

The examinations conducted at Oconee 2 on April 2, 1996 and those conducted at Oconee 3 on October 21, 1996 were capable of reliably detecting flaws with a through-wall extent of 0.100 inch and a length of 0.200 inch. The inspections conducted at Oconee 1 on January 18, 1989 did not use the same ultrasonic technique but were calibrated at an equivalent sensitivity and should have been capable of reliably detecting a similar sized flaw.

Question 2e:

Provide the bases supporting the frequency of inspection of Ultrasonic Testing, Radiographic testing and Volumetric Testing, of the welds in Oconee Unit 1.

Response:

Subsequent to the problems at CR-3, the B&W Owner's Group report developed an augmented inspection plan which specifically applied to Oconee Units 2 and 3. Due to the unique double thermal sleeve design, Oconee Unit 1 was not specifically included in that plan. However, Duke Power stated in a February 15, 1983 letter from Hal B. Tucker to Harold R. Denton that an augmented ISI program had been developed for Unit 1. Details of this plan were not included in docketed correspondence to the staff. However, internal documentation, dated January 28, 1983, stated that the scope of that plan was to "RT and UT the makeup nozzle thermal sleeve/safe end at the 1st, 3rd, and 5th refueling outages from now and every 5th refueling outage thereafter. The HPI only nozzles/safe ends should be RT'ed only at the same frequency." This is similar to the plan for replaced nozzles contained in the BWOG report.

The findings of the task group indicated that cracking would not occur if the thermal sleeve maintained proper contact with the safe end. The RT inspection of the sleeves/safe ends was intended to discover and repair sleeve degradation (loosening) before cracking could become significant.

It was determined at that time that if continued inspections had shown that the sleeves were properly in place, it was not expected that the sleeves would loosen during plant operation prior to subsequent inspections.

The length of time between recommended inspections was lengthened incrementally for all of the HPI/MU nozzles. This is because the

thermal sleeve task force followed a fatigue usage factor type curve for expected damage. It was known at the time that damage was being caused by high cycle/low amplitude thermal stresses. Therefore, fatigue crack initiation and subsequent damage would likely occur much later in time if damage had not occurred early. If the safe ends and sleeves were maintaining their structural integrity for the first five outages and did not show signs of unexpected wear, there was no reason to believe that wear would be accelerated after that time period. It was expected that the same wear rate and forcing functions would be seen in the second five outages as was seen in the first five outages and so on.

Question 4a:

Provide a fracture analysis to determine the critical flaw size required to fracture the piping under normal loads during HPI injection or makeup conditions.

Response:

The metallurgical examination results available at this time indicate that the crack in the pipe to safe end weld has a 360 degree ID crack which is about 25% - 30% through wall except that the crack has propagated through wall for an arc that spans approximately 77 degrees on the OD. The general shape of this flaw configuration will be evaluated in developing responses to questions 4(a-e).

As background, fracture analysis was performed for the austenitic safe end to pipe weld for an HPI nozzle at ANO-1. Crack growth analysis showed that 1225 HPI initiations would be required to propagate a flaw to 50% of the wall thickness and that all ASME Code, Section XI acceptance requirements were satisfied at that flaw size.

Duke Power currently has not completed a fracture mechanics evaluation of the failed crack on the 2A1 nozzle to determine the critical flaw size.

Duke Power will determine the critical flaw size required to fracture the piping under loads during HPI injection (for both nozzles) and during normal makeup (for the HPI/MU nozzle), using the methodology from the ASME Section XI, Appendix C source equations. The analysis will evaluate the effect of varying part wall flaw depth and through wall flaw depth to determine the combination of flaw sizes that will be acceptable. This analysis should be completed by May 9, 1997. The results from this analysis will be used in answering questions 4(a-d).

Question 4b:

In determining the margins-to-failure, identify all assumptions and inputs into the analysis, including stresses and material characteristics.

Response:

Determination of the margin to failure, identification of all assumptions and inputs into the analysis, including stresses and material characteristics will be addressed using analysis similar to that provided in the answer to 4(a) and will be submitted with that analysis. The analysis will show the margin to failure relative that to that required by ASME Section XI, IBW-3600.

Question 4c:

Determine the sensitivity of the critical flaw size and margin-to-failure on the existence of the complex flaw geometry, i.e., 360° internal part through crack and through wall cracking.

Response:

Determination of the sensitivity of the critical flaw size and margin-to-failure on the existence of the complex flaw geometry, i.e., 360° internal part through crack and through wall cracking will be addressed along with the answer to 4(a). A model will be used that determines the limit load (using the same criteria as in ASME Section XI, Appendix C) for a pipe with wall thickness distribution as actually determined from the Unit 2 weld failure analysis. This will be compared to the results obtained for analysis based upon idealized flaw shapes with combined constant through wall depth and constant through wall length.

Question 4d:

Determine the sensitivity of the critical flaw size and the margin-to-safety on the uncertainty in the mechanical and thermo-hydraulic loads at the pipe/safe-end weld.

Response:

Determination of the sensitivity of the critical flaw size and the margin-to-safety on the uncertainty in the mechanical and thermo-hydraulic loads at the pipe/safe-end weld will be addressed in the answer to 4(a).

Question 4e:

Based on the root cause of the cracking, provide an assessment of the time to initiate and propagate a crack through the wall of the piping.

Response:

The failure analysis for the cracked weld in Unit 2 is still on going. Preliminary results show that the crack was most likely initiated and propagated by high cycle thermal fatigue. The striation spacing was about 1 micron (10^{-6} meter). The failure analysis also noted that the crack surface was heavily oxidized, indicating that it had been there for some time.

A simplified fracture mechanics analysis based on the results of the currently available metallurgical evaluation should be completed by May 16, 1997. Supplemental analyses, supported by computational fluid dynamics (CFD), will be conducted to provide an assessment of the time to initiate and propagate the flaw through the wall of the piping. Depending on the complexities associated with this CFD modeling, our expectation is that this work will be completed by the end of June.

Question 4f:

Provide a revised leak-before break analysis based on the complex flaw geometry as found in the cracked and leaking pipe/safe-end flaw.

Response:

Leak-before-break analysis for the pipe/safe-end will be performed using the PICEP Code developed by EPRI for finite-length, through-wall circumferential flaws. Crack models are not available to perform leak-before-break analysis for the complex flaw geometry identified for the Oconee-2 leaking pipe/safe-end flaw. As an alternative, PICEP-based leak-before-break analysis will be performed to approximate the geometry of the Oconee-2 flaw in a conservative manner. In addition, the sensitivity of the leak-before-break results to pipe loads will be investigated by performing the analysis with the normal operating loads and with variations on those loads. This work should be completed by May 9, 1997.

Question 6a:

Describe how the failure of one or more HPI lines is analyzed for the Oconee units, and describe the analyzed consequences.

Response:

As discussed in Chapter 15 of the Oconee FSAR, both large and small break LOCAs are analyzed. The HPI line break is analyzed as one of the postulated small break LOCAs. Only one HPI line is assumed to break. Multiple line breaks are not considered. The analysis uses flow rates that account for the fact that part of the delivered flow of the HPI pumps does not reach the core due to the break location. The first docketed description of an HPI line break that Duke Power is aware of is the 1974 B&W topical report BAW-10191, Supplement 1, "Supplement and Supporting Documentation For B&W's ECCS Evaluation Model Report With Specific Applications to 177-FA Class Plants With Lowered-Loop Arrangement." As documented in the FSAR, the consequences of an HPI line break (or any small break LOCA) meet the acceptance criteria of 10CFR 50.46.

Question 6b:

Describe the limiting single failure and what equipment is relied on to mitigate the potential accident.

Response:

The most limiting single failure that is assumed is that of one train of HPI failing to operate on the opposite side from the postulated initiating break. Oconee has two main injection headers that each split into two lines so that flow is provided to the four cold legs. If a break occurs on one injection line, then the single failure that is assumed prevents any flow from entering the RCS via the other main injection line. Only one cold leg initially receives any flow, and it is at a reduced rate due to the fact that the broken line reduces flow to the intact line. Within 10 minutes of the accident, the operators align HPI flow to the two injection lines on the header that was affected by the single failure by opening cross-connect valves HP-409 or -410 to achieve a higher total flow to the core. Flow from two HPI pumps through two trains is adequate to mitigate the consequences of this accident from full power.

Question 6c:

Review the PRA for Oconee to assess the risk significance of this event. Provide the results of the assessment, and state the actions that would be taken to reduce the potential risk.

Response:

The PRA was reviewed with regard to the HPI line break. Based on the leak before break analysis, the leak rate expected to occur is well within the assumptions of the small break LOCA analyses. Therefore, the frequency of the small break LOCAs assumed in the IPE is essentially unchanged. The mitigation strategy taken credit for is still viable (injection capability would be available through the remaining three nozzles). Furthermore, containment integrity is not affected by this issue.

The Operations Group has been given guidance to heighten awareness for potential RCS leakage, more frequent leak detection methods were instituted, and the removal of any required portion of the HPI System from service, other than required by Technical Specifications, is minimized.

Question 7a:

Describe what actions, beyond those stated in the Justification for Continued Operation (JCO), have been taken to prepare the operators for a potential HPI pipe break for the operating unit.

Response:

No actions other than those listed in the JCO are currently being implemented. However, operator training includes extensive use of and familiarization with station Emergency Operating Procedures (EOPs). The initiation of a small break LOCA, which would result from a postulated High Pressure Injection pipe break, are directly addressed within the procedures.

Operator initial and requalification training addresses various small break LOCA scenarios. Requalification training given to various shift teams in March and April prior to this event, had included a simulator scenario for a small break LOCA. Another small break LOCA scenario, more similar to this event, is used frequently. Therefore, management considers the operators well prepared to address this type of event.

Question 7b:

Describe what actions have been taken to limit the equipment that can be removed from service that is important to mitigating a potential HPI pipe break for the operating unit. Indicate if any administrative controls have been put in place to reduce the allowed outage times or increase the increase required to be available.

Response:

Removal of HPI components/trains is currently being limited to only 1.) required Technical Specification related testing and 2.) maintenance activities required for prudent operation of the system. All other testing and maintenance activities are being deferred to outage periods.

Question 7c:

Describe what additional restrictions have been implemented regarding leakage monitoring, acceptance criteria and action statements over an above those described in the May 2, 1997, JCO for Oconee Unit 1.

Response:

This information was provided to the staff in a Duke letter dated May 3, 1997, "Justification for Continued Operation (JCO) of Oconee Unit 1 Based on Oconee Unit 2 HPI Line Leak, Supplement #1".

Question 8a:

The existing analysis of the HPI line is based on USAS B31.7, Class II standards. In light of the crack found in the pipe / safe-end weld which you attributed to high cycle fatigue, provide justification why the existing analysis of HPI is acceptable.

Response:

References:

1. B & W document # 32-1128224-02, "Revised HPI Nozzle Usage Factor"

2. Duke Power Calculation OSC-1304-06 Rev. D30, "Unit 1 HP Injection East & West Loops and 1" Makeup"

3. Duke Power Calculation OSC-1323-06 Rev.D25, "Bechtel Item 9 System 51A Piping Analysis Problem No's 2-51-24 (Vol. A), 2-51-21 (Vol. G), 2-51-20 (Vol. H), & 2-51-22 (Vol. I)- (Unit 2)"

4. Duke Power Calculation OSC-1342-06 Rev. D24, "Bechtel Item 9 System 51A Piping Analysis for Problem 3-51-18, 3-51-19, & 3-51-20 - (Unit 3)"

5. Duke Power Calculation OSC-1522 Rev. D13, "Reactor Coolant Loop Piping Stress Report."

6. Structural Integrity Associates Document # DUKE-11Q-303-5, Rev. 1, " Class 1 Fatigue Reconciliation for HPI Nozzle"

7. Letter from Mr. L.A Wiens, Senior Project Manager Project Directorate II-2, Division of Reactor Projects-I/II, Office of Nuclear Reactor Regulation, NRC, Washington, D.C. to Mr. J.W. Hampton, Vice President, Oconee Site, dated 7-10-96, Re: Reactor Coolant System Auxiliary Piping Fatigue Analysis Schedule

The original analysis of the Oconee Units 1,2, & 3 HPI/MU piping was conducted to the requirements of ANSI B31.7, Class 2 per References 2, 3, & 4. The analysis of the nozzle and the piping to safe end weld was conducted to the requirements of ANSI B31.7, Class 1 per References 1 & 5. A revised interim nozzle analysis is included in References 3 & 6 to reconcile increased loads on the nozzle from the HPI piping due to replacement of the stop check valves with a two valve (check valve & globe valve) arrangement This valve replacement has been installed for Units 2 & 3, but has not been installed for Unit 1.

The common junction of the two analyses is the piping to safe end weld. The piping to safe end weld was not evaluated in the Class 2 piping calculations. The resultant nozzle loads from the Class 2 piping analyses were used as input to the Class 1 nozzle analysis. The nozzle analysis evaluated the piping to safe end weld, the safe end, and the reactor coolant nozzle to Class 1 requirements

A Class 1 evaluation of several of the branch lines off the Reactor Coolant System, including the HPI emergency make-up and normal make-up piping between the first isolation valve and the reactor coolant loops, is scheduled for completion before August 31, 1999 per Reference 7. Those analyses are currently underway and will include all quantifiable loads for the system. These analyses will not include high-cycle loadings which produced the pipe cracking in Unit 2 because those loadings are not quantifiable at this time.

A common bounding analysis was conducted to qualify both the emergency HPI and the combination HPI/MU nozzles.
For the transients considered in the original analysis of the reactor coolant system piping and nozzles, the transients specified for the emergency HPI nozzle were more severe than those expected for the HPI/MU nozzle. For the HPI nozzle, the transients included thermal shock transients due to emergency injection and testing. These thermal shocks do not have to be

considered for the HPI/MU nozzle since it is designed to run cold, and injection does not produce a thermal shock. The cumulative fatigue usage factor (CUF) calculated for the HPI nozzle safe end was 0.88 (Ref. 3 & 6). A separate CUF was not reported for the HPI/MU nozzle safe end since the HPI nozzle loading enveloped the HPI/MU loading.

The pending Class 1 piping analysis or the existing Class 1 nozzle analysis do not address the high-cycle loadings which produced the pipe cracking in Unit 2 because the thermal sleeve evaluations in 1982 indicated that hot water would not enter the HPI/MU piping at this nozzle.
Class 1 stress analyses cannot include unquantified high cycle loads and therefore cannot be expected to prevent their occurrence. The loadings which result in high cycle thermal fatigue tend to be random in nature and vary significantly from location to location. It is very difficult to accurately quantify these loadings for purposes of a Class 1 analysis.

It is Duke's position that any fatigue analyses must be based on quantifiable design basis loads. Accordingly, any unanticipated or unquantified loads that cause high cycle fatigue must be appropriately monitored to determine their existence and their severity. Oconee will be installing instrumentation on the normal and emergency injection lines on Unit 2 to collect temperature profiles for various locations on the lines. In addition, the Unit 3 A1 injection line will be instrumented. Data collected from this monitoring program will be used to further analyze the thermal cycles that occur on these HPI System injection lines.

Question 8b:

Indicate if pipe/safe end weld was part of the original fatigue analysis for this nozzle.

Response:

References:

1. Duke Power Calculation OSC-1522 Rev. D13, "Reactor Coolant Loop Piping Stress Report."

2. B&W document # 32-1128224-02, "Revised HPI Nozzle Usage Factor" 1982.

3. Structural Integrity Associates Document # DUKE-11Q-303-5, Rev. 1, " Class 1 Fatigue Reconciliation for HPI Nozzle"

A fatigue analysis was performed on the HPI emergency make-up nozzles, including the pipe to safe end weld, as a part of the Reactor Coolant System Stress Analysis for original plant construction per Ref. 1. The analysis was revised per Ref. 2 due to postulation of additional transients following a reactor trip. Later an interim analysis per Ref. 3 was completed to reconcile increased loads on the nozzle from the HPI piping due to replacement of the stop check valves with a two valve (check valve & globe valve) arrangement. As mentioned in the answer to question 8a, this valve replacement has been installed for Units 2 & 3, but has not been installed for Unit 1.

Table 1
Oconee Unit 1
Inspections Associated with 1A1 Discharge Make Up Nozzle

Refueling Outage	ISI Plan Item Number	Weld ID from ISI Plan	Configuration	Type of Insp.	Inspection Results	Inspection Requirements
7	E5.01.001	1PDA1-47	1A1 HPI Nozzle Safe-End Base Material PC. 47	UT	Clear	Generic Letter 85-20
7	E5.01.002	1PDA1-47	1A1 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
8	B05.051.002A	1PDA1-11	1A1 Nozzle to Safe-End weld	PT	Clear	Section XI
9	E04.001.001	1PDA1-47	1A1 HPI Nozzle Safe-End Base Material PC. 47	UT	Recordable	Generic Letter 85-20
9	E04.001.001A	1PDA1-47	1A1 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
10	B09.032.019	1PDA1-10	1A1 HPI Nozzle to 1A1 RCP Discharge Piping (Branch Weld)	MT	Clear	Section XI
11	E04.001.001	1PDA1-47	1A1 HPI Nozzle Safe-End Base Material PC. 47	UT	Clear	Generic Letter 85-20
11	E04.001.001A	1PDA1-47	1A1 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
16	B05.140.003	1-PDA1-11	1A1 Nozzle to Safe-End weld	PT	Clear	Section XI

Table 1 (continued)
Oconee Unit 1
Inspections Associated with 1A2 Discharge Make Up Nozzle

Refueling Outage	ISI Plan Item Number	Weld ID from ISI Plan	Configuration	Type of Insp.	Inspection Results	Inspection Requirements
7	E5.01.003	1PDA2-47	1A2 HPI Nozzle Safe-End Base Material PC. 47	UT	Clear	Generic Letter 85-20
7	E5.01.004	1PDA2-47	1A2 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
9	E04.001.002	1PDA2-47	1A2 HPI Nozzle Safe-End Base Material PC. 47	UT	Recordable	Generic Letter 85-20
9	E04.001.002A	1PDA2-47	1A2 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
11	B09.032.020	1PDA2-10	1A2 HPI Nozzle to 1A2 RCP Discharge Piping (Branch Weld)	MT	Clear	Section XI
11	B05.051.005	1PDA2-11	1A2 Nozzle to Safe-End weld	PT	Clear	Section XI
11	E04.001.002	1PDA2-47	1A2 HPI Nozzle Safe-End Base Material	UT	Clear	Generic Letter 85-20
11	E04.001.002A	1PDA2-47	1A2 HPI Nozzle Safe-End Base Material	RT	Clear	Generic Letter 85-20
13	B09.021.060	1-51A-11-85A	Pipe to 1A2 Safe-End weld	PT	Clear	Section XI

Table 1(continued)
Oconee Unit 1
Inspections Associated with 1B1 Discharge HPI Nozzle

Refueling Outage	ISI Plan Item Number	Weld ID from ISI Plan	Configuration	Type of Insp.	Inspection Results	Inspection Requirements
7	E5.01.005	1PDB1-47	1B1 HPI Nozzle Safe-End Base Material PC. 47	UT	Clear	Generic Letter 85-20
7	E5.01.006	1PDB1-47	1B1 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
9	E04.001.003	1PDB1-47	1B1 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
11	B09.032.021	1PDB1-10	1B1 HPI Nozzle to 1B1 RCP Discharge Piping (Branch Weld)	MT	Clear	Section XI
11	E04.001.003	1PDB1-47	1B1 HPI Nozzle Safe-End Base Material	RT	Clear	Generic Letter 85-20
11	E07.001.003	1-51A-11-89	Pipe to 1B1 Safe-End weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
11	E07.001.004	1-51A-11-90	Pipe to Valve 1HP-153 weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
11	E07.001.005	1PDB1-11	1B1 Nozzle to Safe-End weld & 1 inch base metal	UT	Recordable	NRC Bulletin 88-08
13	B09.021.009A	1-51A-11-89	Pipe to 1B1 Safe-End weld	PT	Clear	Section XI
13	B05.051.008	1PDB1-11	1B1 Nozzle to Safe-End weld	PT	Clear	Section XI
13	E07.001.003	1-51A-11-89	Pipe to 1B1 Safe-End weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
13	E07.001.004	1-51A-11-90	Pipe to Valve 1HP-153 weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
16	G04.001.003	1-51A-11-89	Pipe to 1B1 Safe-End weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
16	G04.001.004	1-51A-11-90	Pipe to Valve 1HP-153 weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08

Table 1(continued)
Oconee Unit 1
Inspections Associated with 1B2 Discharge HPI Nozzle

Refueling Outage	ISI Plan Item Number	Weld ID from ISI Plan	Configuration	Type of Insp.	Inspection Results	Inspection Requirements
7	E5.01.007	1PDB2-47	1B2 HPI Nozzle Safe-End Base Material PC. 47	UT	Clear	Generic Letter 85-20
7	E5.01.008	1PDB2-47	1B2 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
9	E04.001.004	1PDB2-47	1B2 HPI Nozzle Safe-End Base Material PC. 47	RT	Clear	Generic Letter 85-20
11	E04.001.004	1PDB2-47	1B2 HPI Nozzle Safe-End Base Material	RT	Clear	Generic Letter 85-20
11	E07.001.001	1-51A-11-87	Pipe to 1B2 Safe-End weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
11	E07.001.002	1-51A-11-88	Pipe to Valve 1HP-152 weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
11	E07.001.006	1PDB2-11	1B2 Nozzle to Safe-End weld & 1 inch base metal	UT	Recordable	NRC Bulletin 88-08
12	B09.021.008	1-51A-11-87	Pipe to 1B2 Safe-End weld	PT	Clear	Section XI
13	B09.021.009	1-51A-11-88	Pipe to Valve 1HP-152 weld	PT	Clear	Section XI
13	B09.032.022	1PDB2-10	1B2 HPI Nozzle to 1B2 RCP Discharge Piping (Branch Weld)	MT	Clear	Section XI
13	B05.051.011	1PDB2-11	1B2 Nozzle to Safe-End weld	PT	Clear	Section XI
13	E07.001.001	1-51A-11-87	Pipe to 1B2 Safe-End weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
13	E07.001.002	1-51A-11-88	Pipe to Valve 1HP-152 weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
16	G04.001.001	1-51A-11-87	Pipe to 1B2 Safe-End weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08
16	G04.001.002	1-51A-11-88	Pipe to Valve 1HP-152 weld & 1 inch base metal	UT	Clear	NRC Bulletin 88-08