May 26, 2006

Mr. J. A. Stall
Senior Vice President, Nuclear and
Chief Nuclear Officer
Florida Power and Light Company
P. O. Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: ST. LUCIE NUCLEAR PLANT, UNIT 2 - REGARDING REQUEST FOR RELIEF FROM THE REQUIREMENTS OF THE ASME CODE (TAC NO. MC9502)

Dear Mr. Stall:

By a letter dated January 4, 2006, as supplemented by letter dated April 12, 2006, Florida Power and Light Company, et al. (the licensee) submitted Relief Request No. 5 (RR-5), Rev. 1, which requested extension of RR-5 for St. Lucie Plant, Unit 2 for the remainder of the current inservice inspection (ISI) interval. RR-5, Rev. 1, proposes alternatives to certain American Society of Mechanical Engineers (ASME) Code requirements regarding repair of alloy 600 small-bore nozzles without flaw removal.

RR-5, Rev. 1, applies to all previous repairs to alloy 600 small bore nozzles on the hot leg reactor coolant piping and pressurizer that have left a remnant nozzle in place and all similar future repairs, including pressurizer heater sleeve repairs that will leave a remnant heater sleeve in place.

The U. S. Nuclear Regulatory Commission (NRC) staff previously extended RR-5 for one operating cycle, with the expectation that it would provide sufficient time for the NRC staff to complete its review of an industry report and provide guidance for requesting approval to use the alternative repair techniques on a permanent basis. The evaluation of the industry report has now been completed.

The NRC staff has reviewed the licensee's request and has concluded that performance of repair/replacement of the nozzles and pressurizer heater sleeves in accordance with ASME Code requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety, because an ASME Code repair would result in potentially excessive radiation exposure and safety hazards to personnel. Furthermore, there is reasonable assurance that flaws left in place will not impact the structural integrity of the primary pressure boundary.

Therefore, pursuant to Title 10 of the *Code of Federal Regulations,* Section 50.55a(a)(3)(ii), the proposed alternatives of RR-5, Rev. 1, are authorized at St. Lucie Unit 2 until the end of the current ISI interval, which ends on August 7, 2013.

Further details on the bases for the NRC staff's conclusions are contained in the enclosed safety evaluation. If you have any questions regarding this issue, please feel free to contact Brendan Moroney at (301) 415-3974.

Sincerely,

/RA/
Michael L. Marshall, Jr., Chief
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-389

Enclosure: Safety Evaluation

cc: See next page

Further details on the bases for the NRC staff's conclusions are contained in the enclosed safety evaluation. If you have any questions regarding this issue, please feel free to contact Brendan Moroney at (301) 415-3974.

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

INSERVICE INSPECTION PROGRAM

RELIEF REQUEST NO. 5, REV. 1

FLORIDA POWER AND LIGHT COMPANY, ET AL.

ST. LUCIE UNIT 2

DOCKET NO. 50-389

1.0 INTRODUCTION

By letter dated January 4, 2006, as supplemented April 12, 2006, Florida Power & Light Company, et al. (the licensee) submitted Relief Request No. 5 (RR-5), Rev. 1, requesting extension of RR-5 for the remainder of the third 10-year inservice inspection (ISI) interval at St. Lucie Unit 2, which expires in August 2013. RR-5, Rev.1, proposes alternatives to certain American Society of Mechanical Engineers (ASME) Code requirements regarding repair of small bore alloy 600 nozzles welded to the reactor coolant hot leg piping and pressurizer and alloy 600 heater sleeves welded to the pressurizer. RR-5, Rev. 1, applies to all previous repairs to alloy 600 small bore nozzles on the hot leg reactor coolant piping and pressurizer that have left a remnant nozzle in place and all similar future repairs, including pressurizer heater sleeve repairs that will leave a remnant heater sleeve in place.

By letter dated May 18, 2004, the U.S. Nuclear Regulatory Commission (NRC) staff extended RR-5 for one operating cycle. Relief was not granted on a long-term basis because, at the time, the NRC staff was assessing the requirements that would allow the operation of half-nozzle repairs on a permanent basis. In view of the events of significant corrosion of the reactor vessel head at various nuclear plants, the staff was evaluating several technical issues associated with the long-term implementation of the sleeve (full-nozzle) repair and half-nozzle repair, such as the effect of water chemistry on crack growth and the need for periodic volumetric inspections. Also, the staff was reviewing the Westinghouse topical report, "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs," WCAP-15973-P, Revisions 00 and 01.

In a letter to the Westinghouse Owners Group dated January 12, 2005, the staff approved WCAP-15973-P, Rev. 1. Subsequently, Westinghouse incorporated the staff's final safety evaluation into the topical report, which was published as WCAP-15973-P-A, Rev. 1.

Enclosure

2.0 REGULATORY EVALUATION

The ISI of ASME Code Class 1, Class 2, and Class 3 components is to be performed in accordance with the ASME Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," and applicable edition and addenda, as required by Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.55a(g), except where specific relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i). Section 50.55a(g)(6)(i) states that "The Commission will evaluate determinations . . . that [ASME] code requirements are impractical. The Commission may grant such relief and may impose such alternative requirements as it determines is authorized by law and will not endanger life or property or the common defense and security, and is otherwise in the public interest giving due consideration to the burden upon the licensee that could result if the requirements were imposed on the facility . . . ."

Pursuant to 10 CFR 50.55a(a)(3), alternatives to the requirements of 10 CFR 50.55(a)(g) may be used, when authorized by the NRC, if the applicant demonstrates that: (i) the proposed alternatives would provide an acceptable level of quality and safety, or (ii) compliance with the specified requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

Pursuant to10 CFR 50.55a(g)(4), ASME Code Class 1, 2, and 3 components (including supports) will meet the requirements, except the design and access provisions and the preservice examination requirements, set forth in the ASME Code Section XI to the extent practical within the limitations of design, geometry, and materials of construction of the components. In addition, 10 CFR 50.55a(g)(4) requires that inservice examination of components and system pressure tests conducted during the first 10-year inspection interval and subsequent inspection intervals comply with the requirements in the latest edition and addenda of Section XI of the ASME Code that is incorporated by reference in 10 CFR 50.55a(b) 12 months before the start of the 10-year inspection interval.

The applicable code of record for the third 10-year ISI interval at St. Lucie Unit 2 is the 1998 Edition through the 2000 Addenda of the ASME Code, Section XI.

3.0 DETAILS OF LICENSEE'S RELIEF REQUEST

3.1 Component Identification

The affected components are the small bore alloy 600 nozzles welded to the reactor coolant piping hot legs and pressurizer and the alloy 600 heater sleeves welded to the pressurizer at St. Lucie Unit 2.

3.2 Applicable Code Edition and Addenda

ASME Code Section XI, 1998 Edition through the 2000 Addenda.

3.3 Code Requirements for which Relief is Requested

The licensee requests an alternative to the requirements of ASME Boiler and Pressure Vessel Code, Section XI, paragraph IWB-3132.2, *Acceptance by Repair/Replacement Activity*, which requires that “A component whose volumetric or surface examination detects flaws that exceed the acceptance standards of Table IWB-3410-1 is unacceptable for continued service until the additional examination requirements of IWB-2430 are satisfied and the component is corrected by a repair/replacement activity to the extent necessary to meet the acceptance standards of IWB-3000."

3.4 Licensee’s Proposed Alternative to Code

The subject of RR-5, Rev. 1, is the repair of small bore alloy 600 nozzles on the reactor coolant hot leg piping and pressurizer and alloy 600 heater sleeves on the pressurizer.

The licensee stated that all the alloy 600 small bore nozzles on the St. Lucie Unit 2 hot leg piping and on the pressurizer have been replaced with alloy 690 nozzles. No pressurizer heater sleeves have been replaced. The original weld or base metal was not and will not be corrected. The nozzles were and will be repaired by relocating the attachment weld from the inside surface of the pipe or pressurizer to the outside surface of the pipe or pressurizer. Nozzle welds on the hot leg piping and pressurizer have been repaired using the half-nozzle technique and the sleeve technique.

According to the licensee, in the half-nozzle repair, the nozzles are cut outboard of the partial penetration attachment weld between the nozzles and hot leg pipe or pressurizer shell wall, approximately mid-wall. The cut sections of the alloy 600 nozzles are replaced with short sections (half-nozzles) of alloy 690 which are then welded to the outside surfaces of the hot leg pipe or pressurizer. The remainders of the alloy 600 nozzles, including the partial penetration welds, remain in place.

In the sleeve repair, the entire nozzle is removed by machining, and the bore diameter is slightly enlarged. Subsequently, an alloy 690 sleeve is inserted into the bore and rolled into place. The end of the sleeve at the interior surface of hot leg piping or pressurizer is either roll expanded or welded to the interior surface of the hot leg piping or pressurizer to essentially eliminate corrosion of the carbon steel by stopping the replenishment of borated solution in contact with the carbon steel of hot leg piping or pressurizer shell. An alloy 690 nozzle is inserted into the sleeve and the nozzle and sleeve assembly is welded to the exterior of the hot leg piping or pressurizer.

In the half-nozzle and sleeve repairs, the nozzles on the pressurizer and several nozzles on the hot leg piping are welded to pads which were deposited on the exterior surface of the pressurizer or piping using a temper bead technique. The weld pads on the previously repaired nozzles were made with the machine gas tungsten arc welding (GTAW) process. The weld pads made in 1989 used ERNiCr-3 filler metal and the remaining weld pads were made with ERNiCrFe-7 filler metal.

The licensee indicated that the pressurizer heater sleeves will be repaired using the half-nozzle technique. The replacement sleeves will be welded to pads to be deposited on the pressurizer lower head using a temper bead technique.

The licensee stated that the remnant material (weld metal, nozzles and heater sleeves) will not receive additional examination. The new pressure boundary welds, on the exterior surface of the piping and pressurizer, will be examined in accordance with the applicable requirements of the ASME Code Sections III and XI.

3.5 Licensee's Basis for Relief

The licensee stated that industry experience has shown that cracks that could be the source of reactor coolant leakage may develop in the nozzle base metal, heater sleeve base metal, in the weld metal joining the nozzles to the reactor coolant pipe and pressurizer or in weld metal joining the heater sleeves to the pressurizer. The cracks are believed to be caused by primary water stress corrosion cracking (PWSCC). The exact leak path, through the weld or through the base metal or through both, cannot be determined.

The licensee stated further that the removal of all possible leak paths requires accessing the internal surface of the reactor coolant piping and pressurizer and grinding out the attachment weld and any remaining nozzle base metal. Such an activity results in high radiation exposure to the personnel involved which is considered a hardship. Grinding within the components also exposes personnel to safety hazards. Additionally, grinding on the internal surface of the reactor coolant piping increases the possibility of introducing foreign material that could damage the fuel cladding. The topical report, WCAP-15973-P-A, Rev. 1, and the licensee's proposed alternative, show that there is no compensating increase in the level of quality or safety resulting from removal of the cracked metal.

The licensee's nozzle repair is based on the topical report, WCAP-15973-P-A, Rev. 1. Section 2.3 of the topical report evaluates the effect of component corrosion resulting from primary coolant in the half nozzle crevice region between the remnant alloy 600 nozzles and replacement alloy 690 nozzle. Section 2.5 evaluates the effect of component corrosion resulting from primary coolant in a confined crevice, such as the sleeve repair, where the volume of the solution is such that the solution cannot be replenished.

The licensee stated that in the half-nozzle repair, a small gap remains between the remnants of the alloy 600 nozzles and heater sleeves and the new alloy 690 nozzles and heater sleeves. As a result, primary coolant (borated water) will fill the crevice between the nozzles and the hot leg pipe and pressurizer, and between the heater sleeve and pressurizer lower head. Low alloy and carbon steels used for reactor coolant system (RCS) components are clad with stainless steel to minimize corrosion resulting from exposure to borated primary coolant. Since the crevice regions are not clad, the low alloy and carbon steels are exposed to borated water. Therefore, the corrosion rates associated with the crevice of the half-nozzle repair will use the corrosion rates derived in the corrosion analysis in Section 2.3 of the topical report.

According to the licensee, the sleeve repair was not specifically evaluated in the topical report. However, Section 2.5 of the topical report provides an alternate estimate of carbon and low alloy steel corrosion. The corrosion rate previously described is applicable to the carbon and low alloy steel exposed to bulk solutions of boric acid and not to solutions confined in a crevice where the volume of the solution is such that the solution cannot be replenished or refreshed. The geometry of the sleeve repair results in a tight crevice between the alloy 690 sleeve and the base metal of the hot leg piping or pressurizer, which is equivalent or even tighter than that evaluated in Section 2.5. Therefore, the corrosion rates in Section 2.5 of the topical report will be used to evaluate the sleeve repair.

The licensee stated that the topical report demonstrates that carbon and low alloy steel in the RCS components will not be unacceptably degraded by general corrosion as a result of the nozzle and heater sleeve repair. Although some minor corrosion may occur in the crevice region of the replaced nozzles and sleeves, the degradation will not proceed to the point where ASME Code requirements will be exceeded before the end of plant life, including the period of extended operation. Further, available laboratory data and field experience indicate that continued propagation of cracks into the carbon and low alloy steels by a stress corrosion mechanism is unlikely.

The licensee indicated that the topical report evaluates the effects of propagation of the remnant flaws in remnant nozzles and welds by fatigue crack growth and stress corrosion cracking mechanisms. Postulated flaws were assessed for flaw growth and flaw stability as specified in the ASME Code, Section XI, and the results demonstrate compliance with the requirements of the ASME Code, Section XI.

4.0 TECHNICAL EVALUATION

In the safety evaluation approving topical report, WCAP-15973-P, Rev. 1, the NRC staff concluded that WCAP-15973-P, Rev. 1, is acceptable to reference in license applications for Combustion Engineering designed pressurized-water reactors to the extent specified, and under the limitations delineated, in the topical report and in the staff's safety evaluation. In Sections 4.1, 4.2, and 4.3 of the safety evaluation, the staff imposed certain conditions for the use of the topical report.

In its submittal, the licensee addressed each of the conditions specified in the staff's safety evaluation for the topical report. The evaluation of RR-5, Rev. 1, focused on the licensee's response to the staff-imposed conditions, as discussed below:

4.1 Response to Conditions in Section 4.1 of the NRC's Safety Evaluation for the Topical Report

Section 4.1 of the staff's safety evaluation for the topical report states that licensees seeking to use the methods of the topical report will need to perform the following plant-specific calculation in order to confirm that the ferritic portions of the vessels or piping within the scope of the topical report will be acceptable for service through the licensed lives of their plants (40 years if the normal licensing basis plant life is used or 60 years if the facility is expected to be approved for extension of the operating license):

Condition 4.1.1. Calculate the minimum acceptable wall thinning thickness for the ferritic vessel or piping that will adjoin to the MNSA [mechanical nozzle seal assembly] repair or half-nozzle repair.

> In the January 4, 2006, submittal, the licensee presented the limiting allowable diameter for the half-nozzle repair and sleeve repair in lieu of the minimum acceptable wall thickness for the pressurizer or hot leg piping. The details of the calculations are discussed in the licensee's response to various conditions as shown below.
>
> The staff notes that the purpose of Condition 4.1.1 is to ensure that the diameter of the nozzle penetration bore of the pressurizer and hot leg piping will not exceed the limiting

allowable diameter, considering the potential for corrosion. The staff finds that the licensee has satisfied Condition 4.1.1 because the licensee's data show that the nozzle penetration bore diameters of the pressurizer or hot leg piping after the nozzle repair are within the limiting allowable diameter.

Condition 4.1.2. Calculate the overall general corrosion rate for the ferritic materials based on the calculation methods in the topical report, the general corrosion rates listed in the topical report for normal operations, startup conditions (including hot standby condition) and cold shutdown conditions, and the respective plant-specific times (in percentages of total plant life) at each of the operating modes.

In the January 4, 2006, submittal, the licensee stated that the overall general corrosion rate was determined using the calculation methods in the topical report and St. Lucie Unit 2 generation data from January 1, 1995 to December 31, 2004. The percentage of total plant time spent at each of the temperature conditions are shown as follows:

High temperature conditions	93.5 percent
Intermediate temperature conditions	1.5 percent
Low temperature conditions	5 percent

The corrosion rate for each temperature condition is taken from the topical report and is shown as follows:

High temperature conditions	0.4 mpy [mils per year]
Intermediate temperature conditions	19.0 mpy
Low temperature conditions	8.0 mpy

The licensee calculated an overall corrosion rate of 1.06 mpy based on the above data and it is applicable only to the half-nozzle repair.

In a letter dated March 16, 2006, the staff requested additional information regarding the above corrosion rate calculation and asked the licensee to discuss the applicability of the half-nozzle corrosion rate to the corrosion rate for the sleeve repair. In its April 12, 2006, response, the licensee stated that the corrosion rate of 1.06 mpy is applicable to the carbon and low alloy steel exposed to bulk solutions of boric acid and not to solutions confined in a crevice where the volume of the solution is such that the solution cannot be replenished or refreshed. When corrosion occurs within a crevice, the crevice region will fill with corrosion products. The corrosion products occupy a greater volume than the noncorroded base metal from which they originated. The presence of corrosion products in the crevice will prevent access of the corrodent (borated water) to the carbon and low alloy steel, reducing the corrosion rate. Further, corrosion will result in the crevice corrosion product becoming dense and less permeable to the primary coolant. Eventually, the corrosion process will stifle because the steel will become isolated from the coolant.

The licensee stated that the geometry of the sleeve repair results in a tight crevice between the alloy 690 sleeve and the base metal of the hot leg piping or pressurizer, which is equivalent or even tighter than that evaluated in the topical report, Section 2.5.

The licensee stated further that the maximum crevice gap discussed is 0.010 inch. When using the sleeve repair technique, the sleeve is inserted into the nozzle bore and sized to provide a tight crevice with maximum gap of 0.010 inch before expanding. The sleeve is plastically deformed by rolling to provide a metal to metal fit with the nozzle bore. The gap resulting from installation of the sleeve is comparable to the gap in the discussion of the topical report and can be less. The corrosion rates discussed in the topical report are applicable to any tight crevice and are not unique to the design of the MNSA repair. The sleeve repair represents a crevice geometry bounded by the dimensions in Section 2.5 of the topical report. The licensee concluded that the corrosion rates in Section 2.5 of the topical report are applicable. The staff finds that applying the corrosion rate in Section 2.5 of the topical report to the sleeve repair is appropriate and, therefore, is acceptable.

As stated above, the licensee used plant-specific data from January 1, 1995, to December 31, 2004, to calculate the corrosion rate. The staff noted that the sleeve repair was first implemented in 1989 at St. Lucie Unit 2. Therefore, the staff suggested that it would be appropriate to calculate the corrosion rate using the plant-specific corrosion data from 1989 to 2004, instead of from 1995 to 2004. In the April 12, 2006, letter, the licensee responded that the sleeves installed in 1989 were seal welded at the internal interface of the sleeve and hot leg piping, thereby preventing contact between the carbon steel pipe and the borated water. These replacements were preventive, not to correct a leaking nozzle. In the unlikely event that a leak would develop at the original weld between the nozzle and the pipe internal surface or at the seal weld, the presence of any leaking corrodent within the rolled gap would result in the crevice corrosion, as discussed above, and there could be a minor finite loss of carbon steel wall thickness.

The licensee stated that the first half-nozzle repair was made in 1994 and the lifetime corrosion was calculated using that start date and the bulk fluid corrosion rate. According to the licensee, it would not be appropriate to extend the corrosion rate for the bulk fluid to a start time based on the seal welded sleeve repair. The staff agrees with the licensee that using corrosion data from January 1, 1995 to December 31, 2004 is appropriate and the corrosion data from the 1989 repair would not be appropriate.

In the March 16, 2006, letter, the staff asked the licensee to discuss why the bounding corrosion rate on Page 2-6 of WCAP-15973-P-A, Rev. 1, which is more conservative than the licensee calculated 1.06 mpy, was not applied to St. Lucie Unit 2. The licensee responded that, as stated in Paragraph 4.1.2 of the staff's safety evaluation for the topical report, a plant-specific corrosion rate is to be determined and the plant-specific corrosion rate is to be used for subsequent calculations. Accordingly, the plant-specific corrosion rate was used for the calculations, not the more conservative corrosion rate from the topical report. The staff finds that the plant-specific corrosion rate is acceptable for use based on Paragraph 4.1.2 of the staff's safety evaluation for the topical report.

The staff finds that the licensee has satisfied Condition 4.1.2 because the licensee has used the appropriate data to derive a plant-specific corrosion rate.

Condition 4.1.3. Track the time at cold shutdown conditions to determine whether this time does not exceed the assumptions made in the analysis. If these assumptions are exceeded, the licensees shall provide a revised analysis to the NRC, and provide a discussion on whether volumetric inspection of the area is required.

In the January 4, 2006, submittal, the licensee stated that, in accordance with Section 2.3.4 of the staff's safety evaluation for the topical report, the corrosion rate for Combustion Engineering plants is based on a time split of 88 percent at operating conditions, 2 percent at intermediate temperature startup conditions, and 10 percent at low temperature outage conditions. An assessment of operating data for St. Lucie Unit 2 from January 1, 1995, through December 31, 2004, shows a time split of 93.5 percent at operating conditions, 1.5 percent at intermediate temperature startup conditions, and 5 percent of plant time at low temperature outage conditions. Therefore, the time at cold shutdown does not exceed the assumptions made in the analysis.

The licensee added that the plant operating conditions will be reassessed for the resubmittal of this relief request at the start of the next inspection interval, which begins in August 2013. There is no need to track plant operating conditions during the remainder of the current inspection interval, as there is sufficient wall thickness in the more limiting hot leg piping to maintain the limiting allowable diameter until this reassessment is made. As shown in WCAP-15973-P-A, Rev. 1, the most severe corrosion rate for steady state conditions (i.e., at power or shutdown) would occur during operation, outage or shutdown conditions with a corrosion rate of 8 mpy. Using the calculated corrosion rate of 1.06 mpy, from 2003 for 2 years, the wall would have experienced a radial loss of 0.002 inch to date. If the plant remained shut down for the remainder of the inspection interval, approximately 8 years, and experienced corrosion of the steel at the rate shown in the topical report, approximately 8 mpy, there would be an additional loss of 0.064 inch of wall thickness. The total loss, 0.002 inch plus 0.064 inch, would equal 0.066 inch. Doubling the loss to account for a diametrical change and adding the diameter of 1.063 inch, results in a diameter of 1.195 inch at the start of the next inspection interval. A diameter of 1.195 inch is less than the limiting diameter of 1.270 inch identified in WCAP-15739-P-A, Rev. 1. This calculation was performed for a half-nozzle repair only. The licensee stated that the corrosion rate for the sleeve repair has a lifetime diametrical loss of 0.025 inch and, therefore, is bounded by the calculation for the half-nozzle repair.

The staff finds that the licensee has satisfied Condition 4.1.3 because the licensee has demonstrated that the time at cold shutdown does not exceed the assumptions made in the analysis.

Condition 4.1.4. Calculate the amount of general corrosion-based thinning for the vessels or piping over the life of the plant, as based on the overall general corrosion rate calculated in Step 2 [Condition 4.1.2] and the thickness of the ferritic vessel or piping that will adjoin to the MNSA repair or half-nozzle repair.

In the January 4, 2006, submittal, the licensee stated that the amount of corrosion will be determined for two cases: (1) the overall general corrosion rate which is applicable to the half-nozzle repairs, and (2) the corrosion rate for tight crevices which is applicable to the sleeve repairs. The first half-nozzle repair to piping was made in 2003 and the first sleeve repair to piping was made in 1989. The first half-nozzle repair to the pressurizer was made in 1994 and the first sleeve repair to the pressurizer was made in 1995.

The plant license was renewed in 2003 and expires on April 6, 2043. Thus, the first half nozzle repairs, made in 1994, can be expected to see approximately 49 years of service. Applying the corrosion rate of 1.06 mpy for 49 years, results in a radial material loss of 51.9 mils (diametrical loss of 104 mils) for the half-nozzle repairs.

The licensee added that the first sleeve repairs were made in 1989 and can be expected to see approximately 54 years of service. As shown in the topical report, Section 2.5, a reasonable estimate of the lifetime corrosion resulting from a tight crevice will be a radial material loss of 12.5 mils (diametrical loss of 25 mils), which is considered applicable to the sleeve repairs.

For the sleeves that are rolled in the nozzle/penetration bore, the staff notes that the bore may be dilated during certain transients such that the interference fit between the sleeve and the bore could become relaxed. In addition, the sleeve is made of alloy 690 and the piping or pressurizer base metal is carbon steel. The thermal expansion of the two materials is different, which could contribute to the relaxation of the interference fit. The staff postulates that a crevice could be generated between the sleeve and the base metal under this scenario. The borated solution could come in contact with the carbon steel of the piping or pressurizer, which would lead to a leakage path and potential flaw initiation. In the absence of an assurance that this scenario would not occur, a crevice should be assumed to exist between the sleeve and piping/pressurizer base metal, which means that the corrosion rate for the sleeve repair would be similar to, if not the same as, the corrosion rate for the half-nozzle repair. In the March 16, 2006, letter, the staff asked the licensee to address the likelihood of this scenario and, if it is relevant, recalculate the life span of the sleeve repair.

In the April 12, 2006, response, the licensee stated that the alloy 690 sleeve is plastically deformed, at ambient temperature, to the inside diameter of the nozzle bore in the pressurizer or hot leg piping. The coefficient of thermal expansion for alloy 690 base metal is greater than that for the pressurizer or piping base metal. Therefore, at 600 degrees-Fahrenheit (°F), the alloy 690 sleeve will have a larger outer diameter than the bore diameter in the vessel or piping and the interference fit imparted at room temperature will be maintained. In the unlikely case that a separation would occur between the sleeve and the nozzle bore, the gap would be expected to be very small and the corrosion rates applicable to a crevice would apply. The crevice corrosion scenario has a limited material loss resulting in a nozzle bore diameter well within the limits of the ASME Code calculations. Accordingly, there is no need to recalculate the life span of the sleeve repair.

The staff finds that the licensee has satisfied Condition 4.1.4 because the licensee has appropriately calculated corrosion rates for the life of the half-nozzle and sleeve repairs.

Condition 4.1.5. Determine whether the vessel or piping is acceptable over the remaining life of the plant by comparing the worst case remaining wall thickness to the minimum acceptable wall thickness for the vessel or pipe.

In the January 4, 2006, letter, the licensee demonstrated that the resultant diameter is less than the limiting allowable diameter for the half-nozzle and sleeve repairs. Therefore, the hot leg piping and the pressurizer after the nozzle or heater sleeve repair are acceptable for the remaining life of the plant. The staff finds that the licensee has satisfied Condition 4.1.5 because, based on the licensee's corrosion calculation, the hot leg piping and pressurizer after the nozzle or heater sleeve repair are acceptable for the remaining life of the plant.

4.2 Response to Conditions in Section 4.2 of the NRC's Safety Evaluation for the Topical Report

Section 4.2 of the staff's safety evaluation for the topical report states that licensees seeking to reference this topical report for future licensing applications need to demonstrate the following conditions are satisfied.

Condition 4.2.1. The geometry of the leaking penetration is bounded by the corresponding penetration reported in Calculation Report CN-CI-02-71, Rev. 01.

In the January 4, 2006, submittal, the license stated that plant-specific calculations to evaluate fatigue crack growth associated with small diameter nozzles were performed in Westinghouse Calculation Note Number CN-CI-02-69, Rev. 0, "Evaluation of Fatigue Crack Growth Associated with Small Diameter Nozzles for St. Lucie 1 & 2." This report was submitted to the NRC as part of the St. Lucie license renewal application for which a license extension was granted. The licensee stated that the calculations and results in Calculation Note CN-CI-02-69 are equivalent to Calculation Report CN-CI-02-71, Rev. 01. The calculations of CN-CI-02-69 do not address the pressurizer heater sleeves. However, the geometry of the St. Lucie Unit 2 pressurizer heater sleeves is equivalent to that shown in Calculation Report CN-CI-02-71, Rev. 1. Therefore, the geometry of the nozzles on St. Lucie Unit 2 is bounded by Calculation Report CN-CI-02-71, Rev. 1.

The staff finds that the licensee has satisfied Condition 4.2.1 because the licensee stated that the calculations in Westinghouse Calculation Note CN-CI-02-69 are equivalent to and bounded by Westinghouse Calculation Report CN-CI-02-71, Rev. 01.

Condition 4.2.2. The plant-specific pressure and temperature profiles in the pressurizer water space for the limiting curves (cooldown curves) do not exceed the analyzed profile shown in Figure 6-2(a) of Calculation Report CN-CI-02-71, Rev. 01, as stated in Section 3.2.3 of this Safety Evaluation [the staff's safety evaluation for the topical report].

In the January 4, 2006, submittal, the licensee stated that the topical report indicated that the pressurizer cooldown profile analyzed is a 200EF per hour cooldown rate from 653EF to 200EF followed by a 75EF per hour rate to 120EF. The topical report indicates that the fatigue evaluation results are not affected by the choice of cooldown rate from 653EF to 200EF and that the only concern is when the metal temperature is less than 200EF, when the material toughness begins to significantly decrease.

The licensee stated that cooldown of the pressurizer water space is administratively controlled by a plant procedure not to exceed a rate of 75EF per hour for normal operation, which is within the rates shown in Figure 6-2 of CN-CI-02-71. Additionally, fluid temperature is recorded until a temperature of 120EF is attained. Therefore, the temperature profile in the pressurizer water space does not exceed the analyzed profile shown in Figure 6-2 of CN-CI-02-71.

In the March 16, 2006, letter, the staff asked the licensee to describe the corrective actions that will be taken if the cooldown rate exceeded the specified 75EF per hour. The staff also asked the licensee whether it would perform an evaluation of the impacts of an out-of-limit event on the structural integrity of the pressurizer base material (given the existence of remnant flaws in the nozzles or heater sleeves),

In the April 12, 2006, letter, the licensee responded that, if the actual cooldown rate exceeded the administratively-limited rate, this incident would indicate a breakdown in the administrative system or malfunction of equipment. There could be many causes and many corrective actions. If it were to occur, the condition would be evaluated under the licensee's corrective action program. Any required analysis would be completed as part of the evaluation.

The staff finds that the licensee has satisfied Condition 4.2.2 because the licensee has demonstrated that the temperature profile in the pressurizer water space does not exceed the analyzed profile shown in Figure 6-2 of CN-CI-02-71. If the cooldown rate exceeds the analyzed profile, the licensee will take corrective actions.

Condition 4.2.3. The plant-specific Charpy upper shelf energy (USE) data shows a USE value of at least 70 foot-pounds (ft-lb) to bound the USE value used in the analysis. If the plant-specific Charpy USE data does not exist and the licensee plans to use Charpy USE data from other plants' pressurizers and hot leg piping, then justification (e.g., based on statistical or lower bound analysis) has to be provided.

In the January 4, 2006, submittal, the licensee stated that a Charpy USE value of 70 ft-lb was used to support an elastic plastic fracture mechanics analysis of the pressurizer lower shell and the pressurizer lower head. The licensee stated that the analysis was not performed on the upper head because the upper head is not affected by the large insurge transient or thermal stress, which occurs at the lower head and lower shell. When the pressurizer was built, Charpy USE data for the pressurizer was not required and was not determined. However, a nil-ductility transition reference temperature was determined for the pressurizer lower shell (two plates) and lower head, and impact properties (absorbed energy, lateral expansion, and fracture appearance) were determined.

The licensee stated that Charpy USE data was determined for six plates in the reactor vessel shell. The licensee used the Charpy USE data from the reactor vessel shell and relevant pressurizer shell plate test data to demonstrate that the Charpy USE values for the pressurizer shell plates satisfy Condition 4.2.3. The pressurizer lower shell and lower head and the six plates from the reactor vessel are very similar in fabrication. All were made to the same specification, SA-533, Grade B, Class 1, having similar chemistry and received similar heat treatment. The pressurizer lower head and the six plates from the reactor vessel were made by Lukens Steel. The pressurizer lower shell was supplied by Marrel Freres. Since the nine items are similar, the licensee stated that it can be reasonably expected that the USE of the pressurizer lower shell plates and lower head should be comparable to that of the reactor vessel plates.

To predict the Charpy USE for the pressurizer plates, the licensee selected the impact data from reactor vessel plate tests at temperatures comparable to that used for testing the pressurizer plates. There are two pressurizer lower shell plates, with heat numbers NR 60 466-2 and NR 61 734-1. The pressurizer bottom head is heat No. C4754-3.

The licensee stated that the pressurizer lower shell plate, heat No. NR 60 466-2, exhibited an absorbed energy of 72 ft-lb and 35 percent shear at +20EF. The USE value is the absorbed energy at 100 percent shear, and this shear state is obtained by testing at progressively higher temperatures. As the testing temperature is increased, the absorbed energy increases and the percent shear increases. Since the pressurizer lower shell plate, heat No. NR 60 466-2, already exhibits the required 70 ft-lb at low temperatures, it will continue to exhibit and exceed the required value of 70 ft-lb while approaching full shear.

The licensee stated further that for the pressurizer lower head, the absorbed energy at +70EF is 69 ft-lb and the absorbed energy will increase as 100 percent shear is obtained. The licensee stated that it can be reasonably expected that the pressurizer lower head material will exhibit an USE of at least 70 ft-lb.

The licensee stated that the pressurizer lower shell plate, heat No. NR 61 734-1, exhibited absorbed energy comparable to that of the six reactor vessel plates. The impact values of the pressurizer lower shell plate heat No. NR 61 734-1, and the six reactor vessel plates at + 30EF are quite similar for both absorbed energy and percent shear. Since all seven plates [six reactor vessel plates and the pressurizer lower shell plate heat No. NR 61 734-1] have similar chemistry and experienced similar heat treatment and exhibit similar low temperature properties, it is reasonable to expect the USE of the pressurizer lower shell plate, heat No. NR 61 734-1, to be comparable to that of the six reactor vessel plates which exhibit USE well in excess of 70 ft-lb.

The licensee concluded that it is reasonable to expect that the plate in the lower shell and lower head of the pressurizer would exhibit USE well in excess of 70 ft-lb and that St. Lucie Unit 2 is bounded by the analysis in the topical report.

The staff noted that Table 1 of the January 4, 2006, submittal shows that indications were detected on the three pressurizer upper head nozzles at St. Lucie Unit 2 in 1994. In its March 16, 2006, letter, the staff asked the licensee to discuss the root cause of the indications found in the upper head nozzles in 1994 and the likelihood of the indications occurring in the replacement alloy 690 nozzles. In its April 12, 2006, letter, the licensee responded that based on the appearance of a liquid penetrant examination of the indications, it was judged that the root cause of the indications was PWSCC. The indications appeared in the 182 weld metal (shield metal arc welding process weld metal equivalent to alloy 600) that was used to join the nozzle to the pressurizer upper head. The weld was made on the inside of the upper head. The repair was made with the half-nozzle technique, resulting in the new weld being made on the outside of the head. The new nozzles were welded using ER52 weld metal (GTAW weld metal equivalent to alloy 690). The new half-nozzles were made from alloy 690. Both ER52 weld metal and alloy 690 base metal are recognized as resistant to PWSCC and the licensee determined that there is little likelihood of the indications recurring in the repaired nozzles.

The licensee concluded that the USE for the pressurizer lower shell and lower head were acceptable (meaning that their USE exceeded the minimum required USE value of

70 ft-lb). In its March 16, 2006, letter, the staff asked the licensee to confirm that the USE for the pressurizer upper head was also acceptable. In its April 12, 2006, response, the licensee stated that the topical report excludes the upper head from the analysis. The licensee stated that the impact data for the pressurizer upper head is equivalent to that for the pressurizer lower head. Therefore, the USE for the lower head is applicable to the upper head. The licensee concluded that it can be reasonably expected that the lower head will exhibit an USE of at least 70 ft-lb. Accordingly, the USE for the pressurizer upper head is also acceptable. The impact data for the upper head has been added to Table 3 of the relief request, titled “Summary of Charpy Impact Data.”

The licensee stated that an elastic-plastic fracture mechanics analysis was not performed on the upper head of the pressurizer because the upper head is not affected by the large insurge transient or thermal stress which occurs at the lower head and lower shell. The staff believes that the pressurizer upper head is at least as susceptible to cracking as the lower head, even though the upper head may not experience the same insurge transient or high thermal stress as the lower head. Also, the licensee reported that indications were detected in the pressurizer upper head nozzles. Therefore, in its March 16, 2006, letter, the staff asked the licensee to confirm that the elastic-plastic fracture mechanics analysis performed in the topical report bounds the pressurizer upper head at St. Lucie Unit 2. In its April 12, 2006, letter, the licensee responded that the base metal material and the dimensions of the pressurizer upper head are essentially equivalent to the values used in the analysis performed in the topical report. Therefore, the St. Lucie Unit 2 pressurizer upper head is bounded by the analysis in the topical report.

The staff finds that the licensee has satisfied Condition 4.2.3 because the licensee has demonstrated that (1) the pressurizer shell, upper head, and lower head have a USE value of at least 70 ft-lb, and (2) the structural integrity of the pressurizer upper and lower heads is bounded by the fracture mechanics analysis in the topical report.

The concluding requirement of Section 4.2 of the staff’s safety evaluation for the topical report states that "Based on the above evaluation, the staff has determined that the crack can be left in the J-groove weld at small-bore locations for a plant life of 40 years. However, if the licensee plans on using this alternative beyond the 40 years and through the license renewal period, the thermal fatigue crack growth analysis shall be re-evaluated to include the extended period, as applicable, and submitted as a time limited aging analysis in their license renewal application as required by 10 CFR 54.21(c)(1) . . . ."

In the January 4, 2006, letter, the licensee responded that in response to Section 4.1.4 of the staff’s safety evaluation, the first small bore alloy 600 nozzle repair can be expected to see 54 more years of service, which extends beyond the original plant life of 40 years and into the license renewal period. The St. Lucie plant has received an extended license for both Units I and 2. The final safety analysis report (FSAR) for Unit 2, in Chapter 1, describes the aging management programs and time limited aging analysis activities for license renewal. Section 18.3.7 of the Unit 2 FSAR specifically addresses alloy 600 instrument nozzle repairs. This section concludes that "The flaw growth analysis of the Unit 2 pressurizer steam space alloy 600 instrument nozzle repairs has been evaluated and determined to remain valid for the period of extended operation . . . ."

The staff finds that the licensee has satisfied the above requirement because it demonstrated that the flaw growth analysis for the nozzle repair remains valid for the period of extended operation.

4.3 Response to Conditions in Section 4.3 of the NRC's Safety Evaluation for the Topical Report

Section 4.3 of the staff's safety evaluation for the topical report states that licensees seeking to implement MNSA repairs or half-nozzle replacements may use the Westinghouse Owners Group's stress corrosion assessment as the bases for concluding that existing flaws in the weld metal will not grow by stress corrosion if they meet the following conditions:

Condition 4.3.1. Conduct appropriate plant chemistry reviews and demonstrate that a sufficient level of hydrogen overpressure has been implemented for the RCS and that the contaminant concentrations in the reactor coolant have been typically maintained at levels below 10 parts per billion (ppb) for dissolved oxygen, 150 ppb for halide ions, and 150 ppb for sulfate ions.

In the January 4, 2006, letter, the licensee responded that hydrogen overpressure is implemented in the RCS by typically maintaining volume control tank hydrogen overpressure between 25 and 35 psig. RCS contaminant concentrations for dissolved oxygen, halide ions, and sulfate are maintained at less than 5 ppb. All of these values are steady state values. The licensee stated that the RCS water is analyzed for dissolved oxygen and halides three times per week with no interval between analysis to exceed 72 hours. Analysis for dissolved oxygen is not required when the RCS Tavg [average temperature] is less than or equal to 250EF. Analysis for halides is not required when all fuel is removed from the reactor vessel and the RCS Tavg is less than 140EF.

The staff finds that the licensee has satisfied Condition 4.3.1 because RCS contaminant concentrations for dissolved oxygen, halide ions, and sulfate are maintained at less than 5 ppb, which satisfy the requirement specified in Staff Condition 4.3.1.

Condition 4.3.2. During the outage in which the half-nozzle or MNSA repairs are scheduled to be implemented, licensees adopting the topical report's stress corrosion crack growth arguments will need to review their plant-specific RCS water chemistry histories over the last two operating cycles for their plants and confirm that these conditions have been met over the last two operating cycles.

In its January 4, 2006, letter, the licensee responded that the contaminant limits have been maintained at steady state operation during the past two cycles. The licensee reviewed the analysis results for the last two cycles and did not identify any transients.

The staff finds that the licensee has satisfied Condition 4.3.2 because St. Lucie Unit 2 has not had water chemistry transients in the last two operating cycles.

4.4 Clarifications

In addition to the above evaluation, the staff asked the licensee to clarify the following issues related to RR-5, Rev. 1.

In the March 16, 2006, letter, the staff asked the licensee to confirm that the previously performed half-nozzle repairs utilized the same repair method (i.e., welding, installation, design, corrosion calculations, flaw evaluation, and qualification tests) as the half-nozzle repair described in the topical report, WCAP-15973-P-A, Rev. 1. In the April 12, 2006, letter, the licensee responded that all previous half-nozzle repairs at St. Lucie Unit 2 used the same repair method as described in the topical report. The half-nozzle repairs were made in 1994 and 2003 and predate the topical report, which was dated February 2005. The corrosion calculations, as shown by the topical report, performed to support this relief request verify the adequacy of the previous repairs. The base metals and the dimensions of the repairs are bounded by flaw evaluations of the topical report.

In the March 16, 2006, letter, the staff asked the licensee to describe the examination technique, the inspection scope (which areas of the repair were examined and which nozzles were inspected), and inspection results of the nozzle and sleeve repairs made on the hot leg nozzles and pressurizer upper and lower heads since 1989. If a visual examination was performed, the staff requested that the licensee identify the type of visual examination (e.g., VT-1, VT-2, or VT-3).

In the April 12, 2006, letter, the licensee responded that ultrasonic testing (UT) examination was performed on the four steam space nozzles for three ISI periods following the repair. The UT procedure examines the pressurizer base metal for extension of the postulated inside diameter flaw at the internal J-groove weld. The UT was performed in 1995, 1997, and 2001, with no relevant indications. A VT on a previously-repaired nozzle was performed recently. A VT-1 inspection was performed on all the pressurizer instrument nozzles in 2005 with no leaks identified. The equivalent of a bare metal visual was performed, on eight of the nine hot leg nozzles repaired in 1995, during the 2003 refueling outage. No indications of leakage were noted during the 2003 outage. The pressurizer instrument nozzles are routinely inspected for leakage during each refueling outage. The resistance temperature detector nozzles on the hot leg are also routinely inspected for leakage during refueling outages. No leakage has been observed on any of the repaired nozzles.

The staff notes that, in similar nozzle repairs, other licensees have requested relief from the following ASME Code requirements: (A) Section XI, Code Case N-638, which provides requirements for temper bead welding; (B) Section III, Paragraph NB-4622, which provides requirements for postweld heat treatment; (C) Section III, Paragraphs NB-4453, NB-5244, and NB-5245, which provide nondestructive examinations requirements; and (D) Section XI, Paragraph IWA-4540 (or Section III, Paragraph NB-6111.1), which requires a system hydrostatic test after repairs. In the March 16, 2006, letter, the staff asked the licensee to confirm that the proposed repairs for St. Lucie Unit 2 would be performed in accordance with the above ASME Code requirements, or to request relief from the aforementioned requirements. In its April 12, 2006, letter, the licensee confirmed that the proposed repairs were performed in accordance with the aforementioned ASME requirements with an approved exception to IWB-3132.2.

The staff concludes that the licensee has addressed satisfactorily all the staff-imposed conditions in the staff’s safety evaluation for the topical report, WCAP-15973-P-A, Rev. 1. The staff finds that RR-5, Rev. 1, follows WCAP-15973-P-A, Rev. 1, and, therefore, is acceptable.

In the March 16, 2006, letter, the staff requested the licensee to confirm that the external welds of the 26 half-nozzle and sleeve repairs listed in Table 1 of the relief request have been evaluated for mechanical and thermal fatigue in accordance with ASME Section III Class 1 design requirements, and that the Class 1 stress and fatigue criteria will be met for the life of the plant. In its April 12, 2006, response, the licensee stated that the external welds of the 26 half-nozzle and sleeve repairs listed in Table 1 of the relief request have been evaluated for mechanical and thermal fatigue in accordance with ASME Section III Class 1 design requirements. The licensee stated that the Class 1 stress and fatigue criteria were met for the life of the plant. The analysis was based on a 40-year plant life. The licensee further stated that, in support of the St. Lucie license renewal, the various 40-year analyses were demonstrated to be valid for the 60-year extended life. The staff has reviewed this response and finds it acceptable, because the licensee has confirmed that the ASME Section III Class 1 design and fatigue criteria have been met for these welds. This issue is, therefore, resolved.

5.0 CONCLUSION

Based on its review of the licensee's submittal, the staff has determined that the proposed RR-5, Rev. 1, and associated sleeve repair and half-nozzle repair are acceptable. The staff has also determined that the performance of ASME Code repair/replacement would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety, because an ASME Code repair would result in potentially excessive radiation exposure and safety hazards to personnel. Furthermore, there is reasonable assurance that flaws left in place will not impact the structural integrity of the primary pressure boundary. Therefore, pursuant to 10 CFR 50.55a(a)(3)(ii), the NRC staff authorizes the licensee's proposed alternative for the remainder of the third 10-year ISI interval at St. Lucie Unit 2, which ends on August 7, 2013.

All other ASME Code, Section XI, requirements for which relief was not specifically requested by the licensee and approved in this safety evaluation remain applicable, including third-party review by the Authorized Nuclear Inservice Inspector.

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Date: May 26, 2006