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SAFETY EVALUATION

BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 55 TO PROVISIONAL OPERATING LICENSE NO. DPR-13

SOUTHERN CALIFORNIA EDISON COMPANY

STEAM GENERATOR REPAIR PROGRAM AND RESTART

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 1

DOCKET NO. 50-206

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1.0 INTRODUCTION

Because of intergranular corrosion attack on a large number of tubes in the San Onofre Nuclear Generating Station (SONGS), Unit 1 steam generators, the facility was shut down for repairs from April 1980 through May 1981, with an anticipated restart around June 1, 1981. This Safety Evaluation documents the results of the staff review* and evaluation of the steam generator repairs (including the environmental and radiation exposure impact), the impact of the repairs on operation due to changes in core flow rate, the Technical Specification changes necessitated by the repairs, and the reinstatement of a license condition. This Safety Evaluation also provides the basis for the staff approval for Southern California Edison Company (SCE) (the licensee) to return SONGS Unit 1 to power operation.

By letter dated December 10, 1980,[1] SCE submitted a Technical Specification change request which would allow operation as described in the SCE supporting technical report, "Reload Safety Evaluation, San Onofre Nuclear Generating Station, Unit 1, Cycle 8, Revision 1," dated October 1980. This submittal accounted for up to an equivalent 20% steam generator tube plugging. By letter dated April 15, 1981,[2] SCE submitted a report entitled "Reload Safety Evaluation, San Onofre Nuclear Generating Station, Unit 1, Cycle 8, Revision 2," dated April 1981. This submittal accounted for up to an equivalent 15% steam generator tube plugging (the projected final configuration) and a reduced reactor inlet temperature. SCE plans to resume operation at an equivalent 15% tube plugging or less, with the reduced core inlet temperature to determine the extent such reduced temperature operation retards or eliminates corrosion of the steam generator tubes. The proposed Technical Specification changes submitted with the Revision 1 report apply as well to Revision 2. Based on its review of both reports, the staff finds the proposed Technical Specification changes acceptable.

In Sections 2 through 9, this Safety Evaluation presents the staff evaluation of the steam generator repairs and steam generator integrity, as well as the required Technical Specifications and licensing condition to ensure continued monitoring of the steam generator integrity. Section 10 discusses radiological safety, and Sections 11 and 14 discuss accident and transient reevaluation with reduced reactor coolant flow and temperatures. Section 8 addresses the Technical Specification and license change committed to by the licensee in the "Return to Power Report"[3] and Technical Specification changes requested by letter dated May 5, 1981.

2.0 DISCUSSION

SONGS Unit 1 was shut down on April 8, 1980 with a 270-gallon-per-day (gpd) primary-to-secondary steam generator tube leak. Subsequent eddy current inspections and laboratory examinations of 19 pulled tube specimens revealed an extensive pattern of caustic-induced intergranular attack in the region of the tube bundle where sludge had accumulated on the tubesheet.

*An Interim Assessment was issued by the NRC on November 28, 1980.

Although eddy current test capabilities are adequate to detect large cracks, capabilities to detect intergranular corrosion attack in the absence of significant cracks (or grain separations) are still under development. Thus, there is a concern regarding the reliability of the identification of the tubes affected by this intergranular phenomenon. The approach taken, therefore, was to perform sleeving or plugging repairs on all tubes within the zone of the tube bundle where the corrosion phenomenon is believed to be most advanced. The repair boundary encompassing this zone was defined on the basis of eddy current test data, laboratory analysis of pulled tube specimens, and in situ pressure tests of individual tubes. The repair boundaries, as defined by SCE, encompass approximately 7000 tubes which represent about 60% of the total number of tubes in all three steam generators. To minimize the number of tubes to be plugged, the licensee initiated a program to develop, qualify by test, and install sleeves in all accessible tubes within the defined repair boundaries. The sleeves are inserted so they span the defective region of the tubes, thus reestablishing the integrity of the primary coolant boundary.

In order to provide the technical basis for the proposed repair program, SCE submitted Westinghouse Steam Generator Repair Report No. SE-SP-40(80), dated September 1980,[4] and Revision 1 to this report dated March 1981.[5] In addition, SCE sponsored a third-party design review of the sleeving repair program at the Westinghouse Forest Hills facility in Pittsburgh, Pennsylvania, on October 23 and 24, 1980.[9] NRC staff members were present and participated at the proceeding. A transcript was taken at the proceeding and provided to the staff for its review and a non proprietary version has been placed in the NRC PDR Room and local PDR.

SCE submitted the report entitled, "Steam Generator Repair Program, Return to Power Report, San Onofre Nuclear Generating Station, Unit 1, April 1981," with a letter dated April 10, 1981 to support approval to resume power operation at San Onofre Unit 1. The technical basis to support this request includes:

(a) The steam generator inspection results, laboratory findings, and repair boundary justification as presented at the Third Party Design Review on October 23 and 24, 1980.

(b) Westinghouse Report No. SE-SP-40(80), Revision 1, dated March 1981.

(c) The secondary water chemistry program presented to the staff at a meeting on March 22, 1981.

The staff has completed its review of the above information. Based on the safety evaluation herein, NRC staff has concluded that San Onofre Unit 1 can operate with the repaired steam generators without undue risk to the public health and safety.

3.0 STEAM GENERATOR INSPECTION RESULTS

3.1 Eddy Current Inspections

San Onofre Unit 1 was shut down on April 8, 1980 after low level steam generator leakage (i.e., primary to secondary) first observed in February 1980 increased to 270 gpd. The Technical Specification leakage rate limit for this unit is 430 gpd. Subsequent hydrotesting revealed five leaking tubes in steam generator C

(hot leg). Initial eddy current testing (ECT) indicated the source of the leakage to be at the top of the tubesheet elevation. In view of these initial findings, the licensee modified the ECT inspection program to include 100% of the hot leg tubes to at least the first support plate. Additional inspections were performed through the U-bends to satisfy Regulatory Guide 1.83 and to monitor for denting at the support plate elevations. These inspections were performed with multifrequency ECT using a conventional (bobbin-type) probe.

The inspections above the tubesheet region indicated no significant progression of denting at the support plates, U-bend wear indications at the antivibration bars (AVBs), or wastage above the tubesheet region relative to what had been observed in previous inspections. At the top of the tubesheet elevation, however, a total of 260 tubes (in all three steam generators) were identified with indications in excess of the 50% plugging limit. Most of the affected tubes had not been observed with quantifiable top of tubesheet indications in previous years when single frequency (400 kHz) inspections had been performed. However, a review of the previous 400 kHz data for a sample of these tubes indicates that these tubes exhibited distorted tubesheet signals dating back several years suggesting that the degradation was present during these years.

To investigate further the corrosion mechanism in the tubesheet region, a tube containing a field ECT indication of 95% and another containing a nonquantifiable ("complex") signal were removed for laboratory examination. Both specimens were found to contain caustic intergranular attack (IGA) within approximately a 1/4-inch zone at the top of the tubesheet elevation with nonuniform penetration around the circumference of the tube. Maximum penetrations of 95% and 80%, respectively, were observed in these tubes.

3.2 Expanded Program

The observed degradation of the tube containing the "complex" (nonquantifiable) indication plus the fact that the IGA was observed to be confined to a narrow circumferential band indicated the need for additional ECT inspections using a probe which is more sensitive to circumferential flaws. The rotating pancake coil (RPC) probe was selected for this purpose. The RPC inspections were concentrated in the protractor-shaped region of the tube bundle (i.e., between the center and periphery of the tube bundle) where the bobbin coil indications were found. Other tubes at the center and at the periphery of the tube bundle were sampled on a 4 x 4 basis (i.e., 1 out of each 16 tubes).

The number of tubes found to contain pluggable (50% or greater) indications increased by almost a factor of three compared to the number found with the bobbin probe. The new indications tended to occur in the same general protractor-shaped region of the tube bundle as had been observed previously. No RPC indications were observed outside this region in the periphery of the bundle where little or no sludge had accumulated on the tubesheet. In addition, few RPC indications were observed in the central bundle region where the depth of the sludge tended to be at a maximum.

Laboratory analysis of twelve pulled tube specimens indicated the intergranular corrosion attack phenomenon to be quite general throughout the protractor-shaped region where the RPC indications were being observed. All tubes pulled from this region exhibited evidence of IGA whether or not they contained detectable

RPC indications. In general, the IGA tended to be confined to a narrow circumferential band at the top of the tubesheet elevation. However, three tubes pulled from locations at or near the central bundle region, which is a region of relatively deep sludge desposits, exhibited IGA extending to one to two inches above the top of tubesheet.

3.3 Repair Boundary Justification

The proposed repair boundary, inside of which each tube will be repaired by sleeving or removed from service by plugging, generally encompasses all tubes in the bundle with the exception of the outer periphery of the bundle where no RPC indications were found. The licensee has cited the following as justification for the proposed repair boundary:

(a) This region is a region of high tubesheet flow velocity and little or no sludge buildup except near the repair boundary. Sludge measurements taken in the field indicate a correlation between the distribution of sludge above the tubesheet and the observed pattern of ECT indications. All the ECT indications which have been observed are located within the sludge pile region with only a few indications being located under less than 4 inches of sludge. It is believed that the sludge pile acts as a concentrating medium for caustic impurities in the secondary water.

(b) Two tubes located at the repair boundary, and which contained no RPC indication, were removed from the steam generator without fracturing and showed only 20 to 30% wall penetration in the laboratory. Channel head clearance considerations precluded removing tubes from further out in the periphery to confirm that the IGA in this region was similarly limited, or perhaps absent.

(c) A burst test of a removed tube specimen containing a 50% through-wall circumferential crack showed the burst strength to be close to that of a virgin tube (approximately 15,000 psi).

(d) In situ pressure tests to 3000 psi were performed for 22 tubes with RPC indications ranging from zero to 97% with no leakage.

(e) In situ pressure testing of the five leakers in steam generator C indicated that reinforcement from the sludge pile limited leakage to small and stable rates for pressures exceeding 5000 psi (1.0 gpm per tube). In the event of leakage in tubes close to the repair boundary, similar reinforcement can be expected.

(f) Metallographic data indicate the corrosion occurs nonuniformly around the tube circumference indicating that "leak before break" is valid.

4.0 SLEEVING

4.1 General Description

The sleeve design consists of a sleeve of wall thickness designed to provide strength comparable to that of the original tube and is fabricated from thermally treated Inconel 600 tubing. The sleeve material was selected to provide maximum

resistance to corrosion and stress corrosion cracking. The sleeve was inserted inside the 0.650-inch ID of the existing tube (mill annealed alloy 600), joined at the upper end to the inner surface of the tube above the tubesheet elevation, and rolled into the tube and tubesheet at the lower end to form a leak-tight seal. Different sleeve lengths were employed, with the maximum length sleeve being employed for each tube consistent with the available clearance with the channel head bowl upon insertion. Each of the sleeve lengths assures that the sleeve will span the outer tube defects which were initially assumed not to occur above the top of the tubesheet elevation.

The upper joints are of two types: the "reference" joint and the "hybrid" joint. The functional requirement imposed for the "reference" joint is that it provides an essentually leak-free seal. The functional requirement imposed on the "hybrid" sleeve is to limit the primary to secondary leakage from all sleeved tubes consistent with the plant Technical Specifications at a differential pressure of 2560 psi at a temperature of 600°F (i.e., postulated main steam line break (MSLB)). This amount of leakage will maintain accident doses to a fraction of the requirements of 10 CFR 100. The need for the hybrid joint developed as a result of difficulties encountered in the field in fabricating an acceptable reference joint. Approximately 5000 of the 7000 sleeves employ the hybrid joint. In cases where the reference joint did not meet the acceptance criteria or was not evaluated against the acceptance criteria, a hybrid joint was installed immediately below the reference joint. The minimum distance between lowest upper joint and the top of the tubesheet was to be 0.81 inch. This covers both the case of the shorter length sleeves, and the case where there is a combination reference-hybrid joint.

It should be noted that a recent examination (March 1981)[6] of tubes pulled from the central bundle region showed the presence of intergranular attack located as much as 2 inches above the top of the tubesheet. This degradation had not been observed by ECT prior to the removal of the tubes. Consequently, there may be some sleeves in which the joint between the sleeve and the tube will have been made on a portion of the tube that has undergone intergranular attack. Based upon a laboratory test involving a tube with a simulated crack (EDM notch), the forming of the joint is expected to open the intergranular attack such that it will be detectable by ECT. The licensee plugged all such tubes found during the baseline ECT inspection.

4.2 Design Verification Analysis and Testing

Structural analyses of the sleeved tube assembly have been performed by the licensee in accordance with ASME B&PV Code, Section III. Results of these analyses indicate acceptable fatigue performance and adequate structural margins for the full range of normal, operating, transient and accident (e.g., LOCA, MSLB) condition loadings. The structural and fatigue analyses included consideration of stresses in the sleeved tube assembly which could result from hourglassing (i.e., deformation) of the support plate flow slots, or from flow-induced vibration. These analyses considered both the case where the outer tube is intact and the case where the outer tube is completely severed because of corrosion.

Analyses have been performed to establish the minimum wall requirements for the degraded sleeves during normal operation and for postulated accident

conditions. The results of the analysis will be used to set the Technical Specification plugging limit for the sleeves.

For a through-wall crack of sufficient length to result in leakage equal to the plant Technical Specification limit during normal operation, the calculated margin to burst is 2.32. Westinghouse has taken exception to the Regulatory Guide 1.121 criterion that there must be a margin of 3.0 against burst under normal operating pressure (Westinghouse letter NS-CE-1282 dated November 22, 1976,[7] and Section 3A of RESAR-414[8]). Westinghouse has instead used a factor of safety of 2.0 in addition to the requirement that the burst pressure be greater than the maximum MSLB accident pressure differential. Westinghouse has determined that margin to burst exists at the MSLB pressure differential for a through-wall crack which is leaking at less than the 0.3 gpm Technical Specification limit during normal operation (leak before break).

The structural analyses of the sleeved tube assemblies have been supplemented by extensive mechanical and metallurgical testing to verify acceptable structural strength, fatigue performance, and leak-tight integrity of the upper and lower joints. Each of the joints has been subjected to axial load cycling tests to verify the long-term sealing integrity of the joints under the specified operating transients (e.g., heatup/cooldown and plant loading/unloading cycles). For the lower joint and reference upper joint specimens, testing has been completed to support 30 years of operation. Hydrostatic testing to 3728 psi (150% of primary side design pressure) at the conclusion of these tests resulted in no leaks. The loaded cycling tests are being repeated for the reference joint to accommodate recent changes to the fabrication parameters and post process acceptance criteria. For the hybrid joint, specimens have completed axial load cycling equivalent to 5 and/or 10 years' operation. These specimens were then leak tested under pressures and axial loadings corresponding to both normal operation and main steam line break conditions. The results of the hybrid joint leak tests indicate that the leakage for each joint is small and is much smaller than the allowable leakage.

An extensive corrosion program on the effects of caustic on the corrosion and stress corrosion cracking of the sleeving material has been performed involving the use of capsule tests and model boiler tests in which it has been attempted to simulate the actual environment that exists at San Onofre.

4.3 Regulatory Guide 1.121 Analyses

Analyses have been performed to establish the minimum wall requirements for degraded sleeves. A 13 mil (36%) remaining wall thickness has been determined adequate to preclude exceeding the yield stress during normal operation and to assure adequate safety margins against burst during postulated accidents. For this remaining wall thickness, the margin to burst under normal operating pressure is 2.4. As mentioned above, Westinghouse has previously taken exception to the Regulatory Guide 1.121 criterion that there must be a margin of 3.0 against burst under normal operating pressure.

Based upon these results, the licensee has proposed a 54% Technical Specification plugging limit for degraded sleeves. This proposed limit includes a 10% allowance for eddy current error and incremental corrosion between steam generator inspections. Data provided in the Repair Report indicates a burst pressure of 3190 psi for a simulated through-wall crack (EDM notch) of sufficient length to leak at the current 0.3 gpm Technical Specification leak rate limit during normal operation. This provides margin to the maximum pressure differential pressure loading during a postulated main steam line break (thus, leak before break is valid), and a margin of 2.3 with respect to normal operating pressure. With the mutually agreed upon change to the Technical Specification leak rate limit (from 0.3 gpm to 0.15 gpm), these margins are increased.

4.4 Eddy Current Test Capabilities

Eddy current data is provided in the Repair Report[5] to demonstrate the applicability of the conventional bobbin-type ECT probe to the inspection of the sleeved tube assemblies. At the optimum test frequency for the sleeve, the amplitudes of the ECT signals ranged from 70% to 100% of those for a nonsleeved tube for calibration holes of 40% and 100% through-wall depth, respectively. These data indicate the relative flaw sensitivity outside the tubesheet; most of the sleeve length will be located within the thickness of the tubesheet. The Westinghouse investigation[5] indicates that within the thickness of the tubesheet the signal-to-noise ratio associated with a sleeving defect is substantially less than that associated with a flaw in a nonsleeved tube. Thus, Westinghouse has concluded that the sleeve in the tubesheet region will have a higher degree of inspectability than an unsleeved tube in this region.

The inspectability of the tube wall is of interest at and above the upper sleeve joint. The Westinghouse study[5] indicates that the amplitude of the ECT signals for calibration holes in excess of 40% through-wall were approximately 60% of those for nonsleeved tubes at a test frequency of 100 kHz. At a test frequency of 350 kHz, the amplitude sensitivity was reduced to approximately 30% to 40% of that for a nonsleeved tube.

Eddy current inspection of the sleeve joints will present some difficulties, particularly for the reference-type upper joint. The sleeve joints contain a number of features which will produce competing ECT signals making it more difficult to discriminate sleeve or tube wall defects at these locations. The application of multifrequency techniques will provide enhanced capability to discriminate flaw signals from these competing signals. Westinghouse is currently investigating ECT procedures to improve further the inspectability of these regions including the use of magnetic bias techniques and alternate probe types such as the crosswound probe, the rotating pancake probe, and the multicoil surface riding probe.

4.5 Leader Program

To supplement the nondestructive examination (NDE) efforts on the inspection of the sleeved tubes, a "leader tube" program will be implemented to monitor postulated inservice degradation of the upper reference joint. The program will consist of two tubes with through-wall penetrations deliberately made in

the tube wall section spanned by the sleeve prior to sleeving. These through-wall penetrations will expose the upper reference joint to the secondary side environmental conditions. There are also four "control tubes" in the program which have not been penetrated. Destructive and/or non-destructive examinations will provide a data base upon which future actions will be based.

5.0 WATER CHEMISTRY CONTROLS FOLLOWING RETURN TO SERVICE

The corrosion that has occurred on the outer surface of the tubes in the SONGS 1 steam generators has been attributed by the licensee to the presence of caustic in the secondary coolant resulting from improper use of a phosphate water chemistry in this unit. Until recently, the unit had considerable condenser leakage problems, which on a sea-water plant, produce an acidic environment in the steam generator by hydrolysis and reaction of sea water with the phosphates. To prevent excess acidity, the licensee until recently balanced this leakage with injections of NaOH into the steam generators, and excess free NaOH is believed to have been present in the steam generators and concentrated in the sludge pile and the tube-tubesheet crevice area for an extended period of time. Intergranular attack of the type observed at San Onofre has been reproduced in the laboratory with concentrated NaOH solutions in a heated crevice over a 1-year period of time.

The licensee has provided the staff with its proposed chemistry program following the return of the unit to service. This program consists of an extensive cold water and hot water soaking process, similar to that used by other licensees for removing residual phosphates from nuclear steam generators. This soaking will be followed by a meticulous program of chemistry control during restart and during subsequent operation of the unit to prevent the development of either highly acidic or highly caustic environments in the steam generator. During the current shutdown, the licensee has performed an eddy current inspection on all of their condenser tubes and plugged those where a vibration or a fretting problem was developing. The condenser tubes at San Onofre are mixed cupro-nickel and titanium tubes, and the difficulty appears to be in fretting and/or fatigue of the titanium condenser tubes. The utility has committed to operating the San Onofre Unit 1 steam generators with a tight control on condenser leakage in the future. They have also indicated they will increase the average level of phosphate in the steam generator coolant from slightly less than 10 to approximately 20 ppm in order to provide additional buffering against acidic or alkaline swings through condenser inleakage or corrosion product reactions with the phosphates.

6.0 LICENSEE'S PROGRAM

Based upon its review of the transcripts from the Third Party Design Review in October 1980,[9] the March 1981 Repair Report,[6] and discussions with the licensee, the following actions will be accomplished prior to restart:

(1) Plugging and sleeving repairs for all tubes as defined in the March 1981 Repair Report.

(2) Baseline eddy current inspection of all sleeved tubes for the length of the sleeves.

(3) Sleeved tubes exhibiting visable ECT indications attributable to IGA at the upper sleeve joint will be plugged.

(4) Implementation of the Secondary Water Program as provided to the staff on March 25, 1981.

(5) Secondary side hydrotest at 800 psid.

(6) Primary side full bundle hydrotest at 1900 psid.

7.0 EVALUATION

7.1 Scope of Repairs

The scope of the sleeving and plugging repairs performed for the San Onofre steam generators during this outage has been justified by the licensee on the basis of the results of extensive eddy current testing, analysis of pulled tube specimens, and pressure testing of individual tubes degraded by IGA. As evidenced by the results of the laboratory analyses of pulled tube specimens, the capabilities of ECT and ECT data evaluation techniques to detect IGA degradation in the San Onofre steam generators is currently very limited. For this reason and because there is some sludge in regions just beyond the repair boundary, the staff does not discount the possibility that some tubes located outside the repair boundary may contain IGA penetration in excess of the 50% plugging limit. The staff does believe, however, that IGA penetrations in excess of 70% would generally have been detected based upon its review of the data correlations between the field eddy current data and corresponding laboratory findings for pulled tube specimens.

In the meantime, the staff finds that continued operation with the existence of nonrepaired tubes for a limited period of six effective full-power months does not represent an undue risk to public health or safety for the following reasons:

1. In situ-pressure tests of 22 tubes containing RPC indications ranging from 0 to 97% have demonstrated that these tubes would not be expected to fail or leak under pressures associated with a postulated MSLB.

2. The secondary to primary side hydro-testing of the whole bundle at 800 psi (which is the maximum external pressure loading expected during a postulated LOCA) in addition to the 1900 psi primary to secondary hydro tests to be performed prior to restart will provide additional assurance to adequate tube integrity for the nonrepaired tubes.

3. Westinghouse estimates that incremental corrosion penetration during the scheduled 6-month operating interval will not exceed 8% in the nonrepaired tubes. While the basis for this number is very crude, we believe that it reasonably bounds the expected incremental degradation in view of various corrective measures which will be implemented to reduce the rate of IGA penetration; namely hot and cold water soaking prior to restart, revised secondary water chemistry controls, and reduced temperature operation.

4. In the event that leaks do occur in the non-repaired tubes, such leaks would be expected to be small based upon operating experience and the observed non-uniform penetration of the IGA around the tube circumference.

5. A change to the plant Technical Specifications has been incorporated to reduce the primary to secondary leakage rate limit from 0.3 to 0.15 gpm in any one steam generator. In addition, the licensee has proposed additional requirements to shutdown below this limit, depending upon the rate of increase in leakage. This requirement has also been incorporated into the Technical Specifications. The leakage rate limit provides additional assurance against a gross tube failure during normal or postulated accident conditions.

Although the in situ pressure tests which were performed for the five leakers showed that sludge reinforcement at these tubes was effective in limiting leakage to low values for pressure loadings ranging to 6000 psi, the staff cannot be sure that the relatively shallow sludge which exists beyond the repair boundary will be similarly effective during accident conditions. Should the IGA phenomena result in additional leaks in the nonrepaired tubes, the licensee has committed to pressure testing these tubes during the next scheduled steam generator inspection outage provided they are accessible (This will necessitate the use of removable mechanical plugs should tube repairs become necessary prior to the scheduled outage.). Leak events affecting the nonrepaired tubes will be evaluated by the staff; and if necessary, additional tube repairs may be required as a preventive measure.

7.2 Sleeve Verification Analysis and Testing

NRC staff has reviewed the details of the comprehensive sleeve qualification analysis and test program. The staff finds that the sleeved tube assemblies have been designed and analyzed to meet the requirements of Section III of the ASME Boiler and Pressure Vessel Code and that testing and analysis has demonstrated that the fabrication procedures to be used in the field will produce joints of acceptable metallurgical properties, mechanical strength, and leak-tight or leak-limiting capability.

NRC staff has also reviewed the details of the corrosion test program and finds that they are adequate to ensure that the sleeving process will not induce accelerated attack on the tube itself and that the sleeving materials will be more resistant to stress corrosion cracking than the original tubing. Further, the effects of the joining cycle on the corrosion and stress corrosion resistance of the tube and the sleeve have been studied and found to be negligible.

7.3 Regulatory Guide 1.121 Analyses

The proposed 54% plugging limit for degraded sleeves incorporates a safety margin of 2.4 between normal operating pressure and burst pressure. This is less than the margin-of-three criterion in Regulatory Guide 1.121. The staff is currently reevaluating the Westinghouse position that the margin-of-three criterion is overly restrictive and that a margin of 2.0 is appropriate. In addition, the staff is evaluating the adequacy of the 10% allowance to cover eddy current error and incremental corrosion between inspections which has been incorporated into the proposed plugging limit.

The staff will issue its evaluation of the proposed plugging limit about December 1, 1981 which is just prior to the first scheduled inservice

inspection of the sleeved tubes. In the interim, the licensee has agreed to a 40% plugging limit for degraded sleeves which is consistent with the 40% plugging limit in the Westinghouse Standard Technical Specifications. The staff has determined that the interim 40% plugging limit satisfies the Regulatory Guide 1.121 margin-of-three criterion, and in addition provides a total allowance of 16% for eddy current error and incremental corrosion, and is acceptable.

With regard to through wall cracks, the staff review indicates that the 2.3 margin against burst associated with the San Onofre sleeves and the current 0.3 gpm Technical Specification leak rate limit is consistent with the margins that exist with many of the operating steam generators. Taking this into consideration and based upon the fact that there is in excess of 20% margin to burst under a postulated main steam line break, we find that the 2.3 margin against burst (for the case of a through-wall crack) associated with the San Onofre sleeve design and current Technical Specification leak rate limit is adequate.

7.4 Inspectability of Sleeves

With the exception of the reference upper joint, the San Onofre sleeve design does not present significant new difficulties from an inspectability standpoint compared to sleeves that have been previously reviewed by the staff and installed in the Palisades steam generators. For these latter sleeves, laboratory testing by Combustion Engineering demonstrated adequate inspectability using a conventional probe and a modified version of the rotating pancake probe using single frequency techniques. Based upon laboratory ECT data provided in the March 1981 Repair Report[6] and our experience regarding ECT capabilities, a conventional probe inspection will provide adequate inspectability of the sleeve wall between the upper and lower joints, although with some loss in sensitivity relative to an unsleeved tube. Defects that occur in the outer tube could produce signals which may tend to mask a sleeving defect. However, multi-frequency techniques, and if necessary, small pancake probes should reduce this effect. With the possible exception of the reference upper joint, available eddy current techniques and alternate probe types can be adapted to permit an adequate inspection of all regions of the sleeve and tube walls which are of interest including the joint regions.

With regard to the upper reference joint, Westinghouse has noted that eddy current testing will generally not be capable of monitoring the development of a leak path between the sleeve and tubewall. The staff does not consider this to be of particular concern since any resulting leak would be very small due to the small gap which exists between the sleeve and tube wall at the joint. The staff is more concerned about the detectability of sleeve and tube wall degradation at this location. Westinghouse is pursuing development of eddy current techniques to perform an inspection of this region.

The staff notes that additional assurances of joint integrity can be obtained through in situ pressure testing of individual sleeved tubes, and through removal of tubes for laboratory analysis and testing. The "leader program" proposed by the licensee provides an example as to how such a program could be accomplished. The staff does not plan to evaluate the licensee's specific

proposals concerning the leader program until inspection capabilities in the upper joint region have been better defined by the licensee and Westinghouse.

The licensee has not made a specific proposal regarding which inservice inspection techniques and probes are to be used to inspect the sleeve and tube walls in the vicinity of the joints. The inspectability of the joint regions using a conventional probe has not been demonstrated. This includes the sleeve and tube walls at the joints themselves and at the expansion transitions, and the tube wall opposite the sleeve ends. Eddy current capabilities in this regard shall be demonstrated when the licensee submits its inspection program for the next scheduled steam generator inspection [see 8.0(3) below].

7.5 Secondary Water Chemistry Programs

The flushing program and secondary water chemistry controls proposed to the staff at the March 25, 1981 meeting are satisfactory. The staff notes, however, that the licensee proposes to increase the average level of phosphate in the steam generator from slightly less than 10 to approximately 20 ppm in order to provide additional buffering against acidic or alkaline swings through condenser inleakage or corrosion product reactions with the phosphates. Whereas increasing the phosphates will provide such an additional buffer, it may also lead to increased difficulties with phosphate hideout and/or possible phosphate wastage corrosion problems, that have been observed by other plants. Consequently, subsequent steam generator inspections, particularly on the cold leg side where the tubes are not sleeved, should include an investigation on the possibility that phosphate-wastage-type degradation has increased following return to service.

8.0 TECHNICAL SPECIFICATIONS TO MONITOR STEAM GENERATOR INTEGRITY

To support its request for return to power, the licensee proposed Technical Specification changes to the plugging criteria of degraded steam generator tubes. In addition, in the April 1981 Return to Power Report[3] the licensee committed to revise their primary to secondary leak rate limits and to perform a steam generator inspection within 6 effective full-power months after restart. The staff reviewed the licensee's commitments and proposed Technical Specification changes and reached agreement with the licensee for the following license condition and Technical Specification changes:

(1) Modification to the primary to secondary leak rate limits as described in the April 1981 Return to Power Report.[3] The reactor would be placed in hot standby within 6 hours and leaking tubes repaired if, the primary to secondary leakage increased 0.1 gallons per minute (gpm), or leaked in excess of 0.15 gpm in any steam generator or increased 0.01 gpm when measured total leakage is above 0.1 gpm.

(2) In the event the previous 0.3 gpm Technical Specification leakage limit is exceeded prior to shutdown, eddy current inspections will be performed in addition to performing tube repairs.

(3) The plant shall be shutdown within 6 effective full-power months following restart for a steam generator inspection. The inspection program shall be submitted for staff review at least 45 days prior to the scheduled shutdown. NRC approval shall be required for restart following the 6-month inspection outage.

(4) The staff evaluation of the proposed plugging limits for degraded sleeves will be issued about December 1, 1981. In the interim, the licensee has agreed to a 40% plugging limit for degraded sleeves consistent with the plugging limit in the Standard Technical Specifications for Westinghouse Pressurized Water Reactors (NUREG-0452, Revision 2).

The staff finds that these Technical Specification changes and the license condition are consistent with our review of the steam generator repair and provide assurance that tube degradation is adequately monitored and are acceptable. The proposed plugging limit of 54% for the sleeves will be reviewed and resolved about December 1981.

9.0 SUMMARY CONCERNING STEAM GENERATOR REPAIRS AND ASSOCIATED TECHNICAL SPECIFICATION CHANGES

Overall, the staff concludes that the proposed sleeving repair method provides a sound technique for restoring the integrity of degraded or defective steam generator tubing as a primary pressure boundary, and, thus, provides an acceptable alternative to tube plugging as a repair procedure.

On the basis of the above evaluation, NRC staff concludes that San Onofre Unit 1 can be returned to power without undue risk to public health or safety subject to the completion of all proposed repairs, corrective actions, and tests (see Section 6.0).

The staff has also concluded that the Technical Specification changes and the license condition described in Section 8.0 are acceptable.

10.0 OCCUPATIONAL EXPOSURE BECAUSE OF STEAM GENERATOR REPAIRS

10.1 Description of Personnel Access

The repair of the steam generators at San Onofre 1 required a considerable amount of personnel access to the steam generator channel heads. The shutdown gamma dose rates of these channel heads prior to initiation of the sleeving project was approximately 10 rem/hr. The major source of the radiation dose rate inside the steam generator channel head was a tenacious layer of oxide which includes deposited activated corrosion products. In order to remove this deposited activity from the inside of the channel head and thereby reduce dose rates in the region, Southern California Edison used a Westinghouse mechanical decontamination process involving grit driven by a high pressure water spray. A grit blaster was cam-locked to the steam generator tube sheet and operated remotely from a low dose rate area. After the hot leg channel heads were decontaminated, SCE cleaned the bottom few feet of each tube to remove deposited radioactivity and to reduce the gamma radiation shine to the workers.

To further reduce the doses to personnel working in the channel head, lead shielding was placed; (a) on the cold leg side of the divider plate to eliminate cold leg streaming to the hot leg plenum, (b) over the opening of the hot leg inlet pipe, (c) on the bottom of the tube sheet to cover portions of the tube sheet not being worked on, and (d) on the floor of the plenum. These decontamination and shielding techniques served to reduce the dose rates inside the hot

leg channel heads by a factor of approximately 3.4. In order to minimize worker time spent inside the steam generator plenum, SCE used remote techniques where practicable. Most of the channel head decontamination and preparation of the inside surfaces of the tubes was done remotely using an x-y positioner machine.

Following decontamination of the steam generator channel heads, the licensee began the tube sleeving operation. Reference design sleeves were inserted in some of the out-of-sludge region tubes and leak limiting sleeves (hybrid sleeves) in the sludge region tubes. Installation of a reference design sleeve involves seven separate operations; (1) attachment of latching mechanism and mandril to the tubesheet, (2) insertion and latching of sleeve into tube, (3) expansion of sleeve, (4) hardrolling of sleeve, (5) removal of latching mechanism, (6) heat treating of sleeve, and (7) ultrasonic testing of heated joint. Installation of a leak limiting sleeve involves five operations. SCE used a combination of remote and semiremote techniques to perform these jobs. A total of approximately 7000 tubes for the three steam generators were sleeved. Tubes having a high degree of degradation and tubes which cannot be sleeved were plugged. SCE and Westinghouse provided training including use of mockups, to the maintenance crews performing the steam generator maintenance work to minimize the time spent in the radiation fields. SCE has also employed many ALARA measures, discussed in the following section, to minimize worker doses.

10.2 As Low as Reasonably Achievable (ALARA) Considerations

SCE committed to making every reasonable effort to maintain occupational radiation exposures ALARA in accordance with 10 CFR Part 20.1(c) and Regulatory Guide 8.8, Rev. 3, "Information Relevant To Ensuring That Occupational Radiation Exposures at Nuclear Power Stations Will Be as Low as Is Reasonably Achievable," Prior to beginning the tube sleeving project, SCE employed decontamination and shielding techniques on the steam generator channel heads to reduce dose rates by a factor of approximately 3.4. Wherever practicable, work on the steam generator was performed remotely, or semiremotely, with the aid of remote or semiremote tooling and remote closed-circuit TV monitoring. Steam generator entrants are suited up in a low background area prior to containment entry. The steam generator channel head areas are ventilated to control airborne concentrations. Steam generator platform areas are continuously monitored using remote-readout gamma detectors and are routinely air sampled and surveyed for contamination using long-reach survey instruments. Multiple stepoff pads are used in the steam generator platform areas to confine the spread of contamination. Occupied areas, walkways, and platforms in containment have been shielded to reduce dose rates to personnel and these areas are surveyed for contamination each shift.

As recommended in Regulatory Guide 8.8, training for steam generator entrants includes the use of full-scale mockups of the steam generator plenum and surrounding work area. Workers, dressed in protective clothing, were trained using the same tools that are used during the sleeving work. The three days of training that all steam generator entrants received included health physics training and instruction in the wearing of protective clothing, in addition to the job training. After an NRC inspection and review of dosimetry procedures, SCE required the steam generator repair workers to wear a series of TLDs to measure doses to their chests, heads, and extremities. Resulting worker doses were input into a computer by work function and location. Daily exposure updates by work group and major task were sent to upper level management for review.

SCE's efforts to maintain occupational doses ALARA during the repair work are in accordance with the guidelines of Regulatory Guide 8.8 and are acceptable.

11.0 DISCUSSION OF REDUCED FLOW OPERATION

Each of the three steam generators has 3,794 tubes. The licensee has stated that each plugged tube blocks a flow area equivalent to 13 sleeved tubes. As of April 15, 1981, the licensee projected the following modifications to the steam generators:

	Steam Generator		
	A	B	C
% Flow Area Blocked	13.8	11.9	12.0
Design Flow, gpm	64,200	65,900	65,600

The licensee submitted a Reload Safety Evaluation[1] which described the effects of the steam generator modifications on the transient analyses. This Westinghouse topical report presents an evaluation for Cycle 8 operation which demonstrates that the core reload will not adversely affect the safety of the plant. The licensee assumed a total flow area blockage of 20% and total reactor coolant system flow reduction of 6.6%. As shown above, the assumed 20% flow area reduction is conservative. Similarly, the licensee estimates that the actual reactor coolant system flow reduction is approximately 4%.

The licensee's analyses assume that the flow blockage is uniform among the three steam generators. Based on the above projected modifications and sensitivity studies discussed in the LOCA evaluation, the staff concurs with the licensee that additional analyses assuming nonuniform flow blockage among the three loops is not necessary.

The nominal design parameters for Cycle 8 are: 1347 MWt (100% rated core power); 2100 psig system pressure; core inlet temperature of 551.5°F; 4.64 kW/ft average linear full power density; and a 195,000 gpm Reactor Coolant System (RCS) Total Design Flow (TDF) (93.4% of Cycle 7 TDF).

The proposed Technical Specification (TS) changes attributable to the steam generator modifications have been assumed in the analyses. They are as follows: specific power is reduced from 13.97 to 13.7 kW/ft; and F_q is reduced from 2.95 to 2.89. The positive and negative incore axial offset limits have been changed from

$$\frac{2.95/P - 2.1225}{0.03084} - 3.0$$

to

$$\frac{2.89/P - 2.1225}{0.03021} - 3.0$$

and from

$$\frac{2.95/P - 2.1181}{-0.03132} + 3.0$$

to

$$\frac{2.89/P - 2.1181}{-0.03068} + 3.0$$

where P = Power

The variable low pressure trip (DNBR) setpoint has been changed from $\geq$ 14.45 (1.3130 $\Delta T + T_{avg}$) - 7298.7 to $\geq$ 26.15 (0.894 $\Delta T + T_{avg}$) - 14341.

A new pressure temperature combination for a locus of points with power level is also incorporated into the TS.

12.0 EVALUATION OF OPERATION WITH REDUCED FLOW

12.1 Nuclear Design

As a result of the LOCA analysis for 20% steam generator tubes plugged, the $F_Q^T xP$ limit for Cycle 8 is 2.89. This limit was 2.95 in Cycle 7. The licensee has presented the results of an analysis which shows the maximum predicted $F_Q^T xP$ as a function of axial offset for Cycle 8. This analysis was performed using techniques which have been standard for previous cycles of San Onofre Unit 1, and were used for all Westinghouse-designed reactors before the advent of the constant axial control mode of limiting operating peaking factors.

The analysis includes consideration of maneuvers allowed by the plant Technical Specifications, and operator errors such as failure to recognize and control xenon transients. The set of maneuvers and faults analyzed is extremely conservative relative to those which typically occur at the power plant. The results show that, provided the axial offset and control rods are controlled to the limits allowed by the Technical Specifications, the $F_Q^T xP$ limit of 2.89 will not be exceeded.

Therefore, since the analysis shows that the Interim Acceptance Criteria limits for LOCA continued to be met for Cycle 8, we find the $F_Q^T xP$ limit of 2.89 and attendant Technical Specification changes are acceptable.

12.2 Thermal and Hydraulic Design

As a result of the decrease in core flow associated with steam generator tube plugging and sleeving the core thermal hydraulic limits for Cycle 8 will be more restrictive. The core thermal hydraulic limits are based on: (1) a minimum departure from nucleate boiling ratio (DNBR) of 1.3; and (2) avoidance of bulk boiling at the core exit. In addition to the 6.6% reduction in the design flow, the DNB design axial power shape has been changed for Cycle 8.

The reduction in core flow has been accounted for by recalculating the core safety limits, the variable low pressure trip setpoints and the minimum DNBR during transients using 195,000 gpm (93.4% of the Cycle 7 total design flow). The increase in axial peaking has been accounted for by taking credit for approximately one-half of the excess thermal margin which was identified as available for Cycle 7.

The calculations of the core safety limits and trip setpoints were performed using previously approved methods as described in the Westinghouse topical report, "Design Bases for the Thermal Overpower ΔT Trip Functions," WCAP 8745, March 1977.[11] The revised safety limits (Technical Specification Figure 2.1.1)

therefore differ from the present safety limits in both format and in parameter values. The staff has reviewed these revised safety limits and the revised trip setpoints and finds them acceptable. Acceptable safety limits could be developed using either the old or new format since either format can be used to define the condition associated with the limit on Departure from Nucleate Boiling. The new safety limits also account for the reduced flow associated with tube sleeving and plugging.

12.3 Loss-of-Coolant Accidents (LOCA)

The LOCA analyses were reevaluated assuming 20% of the steam generator flow area was blocked. This assumption changes the flow resistance, primary coolant flow, and mass inventory; thus affecting the reactor coolant system blowdown, lower-plenum-refill/core-reflood characteristic for the LOCA analysis. The licensee reanalyzed the previously determined worst break, a double-ended cold leg guillotine (DECLG) with a discharge coefficient (C_D) of 0.6. A peak cladding temperature (PCT) of 2272°F was calculated assuming 102% licensed core power, 2100 psia system pressure, 195,000 gpm primary coolant flow, 13.7 kW/ft and F_Q = 2.89. We asked the licensee to provide assurance that the shape of the break spectrum curve did not change with the Cycle 8 modifications and that the DECLG break with a C_D = 0.6 is still the worst break. The licensee performed a recalculation for the DECLG with a CD = 0.8 which yields a PCT of 2202°F, which is lower than the CD = 0.6 DECLG break. Previous ECCS calculations[12,13] show that a DECLG with a C_D = 0.4 yields PCT at least 330°F below the worst break assuming 10% uniform steam generator plugging and should not become limiting with Cycle 8 modifications. The worst small break from previous analyses[13,14] show that a PCT margin of at least 1000°F exists between the worst break and the worst small break.

The staff asked the licensee to provide a sensitivity study showing the effect of nonuniform steam generator plugging on primary system blowdown and reflood characteristics. The results of the study showed that only minor perturbations occur in the LOCA transient. Therefore, it is acceptable to assure uniform plugging of the steam generator in determination of the PCT for San Onofre Unit 1.

Since the worst-break PCT remains below the interim acceptance criteria limit of 2300°F with the Cycle 8 modification, the LOCA analysis is acceptable to the staff.

12.4 Non-LOCA Transients

Plugging and sleeving the steam generator tubes reduces the primary coolant system flow rate, volume, and the rate of heat transfer to the secondary system. The licensee has investigated the effects of these modifications in the Final Safety Analysis Report (FSAR) transient and accident analyses. Only those postulated faults that were considered to be affected by the modification were examined. Of these postulated faults that were reexamined, only the limiting cases were reanalyzed. The remaining faults were shown to be less limiting qualitatively.

A reactor coolant pump locked rotor is a postulated accident which was not included in the San Onofre design basis. The licensee is examining this transient as part of the Systematic Evaluation Program (SEP) and has committed to submit the reanalyses by August 31, 1981. The SEP review will consider all Condition II, III and IV faults. The staff believes that deferring this to the SEP review is justified. This is because the Surry plant (also a Westinghouse three-loop plant) analyzed the reactor coolant pump locked rotor while assuming 40% steam generator tube blockage and concluded that it was not a limiting transient.[15]

The staff reviewed the Surry submittal and concurred with the licensee's assessment.[16] Therefore, we conclude that a reactor coolant pump locked rotor transient on the San Onofre plant would not result in unacceptable consequences; and that it is acceptable to allow plant operation prior to confirmation of this assessment in the SEP.

The non-LOCA transients examined by the licensee are discussed below:

12.4.1 Control Rod Withdrawal From a Subcritical Condition

The control rod withdrawal from a subcritical condition results in an uncontrolled addition of reactivity which leads to a power excursion. The power response is quickly terminated by the reactivity feedback of the negative fuel temperature coefficient. Although the power excursion causes a heatup of the moderator, the actual temperature increase is small since the power response is primarily a function of the Doppler temperature coefficient. The reduced reactor coolant system flow would tend to increase the fuel and moderator temperature thus adding to the Doppler feedback. Therefore, the transient is only moderately sensitive to reactor coolant flow.

12.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

This transient produces a steam flow core power mismatch, resulting in an increase in RCS temperature. The reduced RCS flow and increased RCS outlet temperature result in less initial margin to DNB. The licensee has recalculated core thermal and hydraulic safety limits consistent with the reduced RCS flow. Based on the new protection limit lines, the variable low pressure setpoint equation constants have been recalculated with new core limits. The licensee reanalyzed this event to verify the adequacy of the protection setpoints and the lead/lag time constants. The setpoints for the variable low pressure reactor trip are consistent with those in the proposed Technical Specifications with allowances for instrument errors, and the reduced flow of 195,000 gpm for RCS flow. This resulted in a minimum DNBR of 1.313. This is acceptable since the nuclear flux and variable low pressure trips prevent the minimum DNBR from falling below 1.3.

12.4.3 Boron Dilution

Reactivity may be added to the reactor by feeding a more dilute boric acid solution than is present in the reactor coolant. Cycle 8 modifications will not affect the FSAR except for dilution with the reactor in manual control. With a maximum reactivity insertion rate of 10^{-5} $\Delta\rho$/second, as assumed in the FSAR, a continuous dilution for approximately 21 minutes would be required to lose

the TS required 1.25% $\Delta\rho$ shutdown margin. For the dilution rate of 10^{-5} $\Delta\rho$/second, the variable low pressure trip will occur approximately 102 seconds after dilution begins from full power with minimum reactivity feedback. Therefore, the FSAR conclusions are still valid and acceptable.

12.4.4 Startup of an Inactive RCS Loop

Technical Specifications prohibit operation with a loop out of service at greater than 10% power. The FSAR shows that the reactor is tripped on the overpower trip. This trip is unaffected by flow reductions. This trip is conservative for operation at less than 10% power since the low overpower trip setpoint of 25% of nominal is activated below 10% power. The lower loop flow also results in slightly lower reactivity insertion rate. The peak heat flux will not exceed 100%, so adequate DNB margin exists.

12.4.5 Addition of Excess Feedwater

Addition of excess feedwater is an excessive heat removal incident which results in a power increase due to moderator feedback. The reduction in primary coolant flow will result in slower cooldown and hence, a lower reactivity insertion rate. Operating at new system conditions should not affect the consequences of this transient since the protection system setpoints were derived to terminate such transients before a DNBR of 1.3 or the limiting fuel centerline temperature is reached.

12.4.6 Large Load Increase

Excessive load increase events, in which steam load exceeds the core power, result in an RCS temperature decrease. The reduced RCS flow due to the steam generator modifications will further decrease the RCS temperature. Protection for this event is provided by the overpower and variable low pressure protection setpoints (VLPPS). The VLPPS have been changed to account for the reduced total RCS flow.

12.4.7 Dropped Rod

The drop of a control rod assembly results in a decrease in reactivity and a corresponding decrease in core power, thus reducing the coolant average temperature. Rod block protection system initiates a turbine runback to match load with core power to limit the temperature and pressure reduction. The effects of the lower RCS flow will be a smaller reduction in coolant average temperature and less of a power overshoot. The licensee performed a DNB evaluation based on a peak power overshoot of 103% of nominal power in conjunction with a 7% reduction in flow. The results show that a DNBR limit of 1.3 can be accommodated with margin in the current cycle.

12.4.8 Control Rod Ejection Accident

The licensee analyzed the rod ejection event at full power and hot standby for beginning of life (BOL) and end of life (EOL). A reduction in core flow will result in a reduction in heat transfer to the coolant which will increase clad and fuel peak temperatures. The analyses show that conditions at the hot spot

fuel rod do not exceed 2300°F for maximum peak cladding temperature, and 4700°F for maximum fuel pellet centerline temperature, and the maximum fuel enthalpy of 170 cal/gram. The results are, therefore, acceptable.

12.4.9 Loss of Coolant Flow

The loss-of-flow transient is caused by simultaneous loss of electrical power to all reactor coolant pumps. This transient was reanalyzed to determine the effect of steam generator tube blockage on the minimum DNBR because reduced initial primary flow results in less margin to the 1.30 DNBR limit. This event is limiting with respect to DNB. The reactor trips on low reactor coolant flow generated at 82% of the new nominal flow and the minimum DNBR remains above 1.3. The complete loss of flow case is more limiting than the loss of a single pump with all loops in service.

12.4.10 Loss of Load

For a loss-of-load event, the core power exceeds the secondary side heat extraction causing an increase in core cooling temperature. When reactor trip on turbine trip is not assumed, a significant pressure increase occurs. The FSAR demonstrated that pressure-relieving devices for both the primary and secondary systems were adequate to relieve the increase in pressure. A reduction in RCS flow and mass inventory results in a more rapid pressure rise. This is not significant since the reactor is tripped on high pressurizer pressure or high pressurizer level with a shorter time to reactor trip resulting in lower energy input into the coolant. DNBR does not decrease below its initial value and the revised variable low pressure trip setpoint assures adequate margin to DNB.

12.4.11 Steamline Break Accident

The steamline break (hypothetical case) is analyzed for hot zero power and EOL conditions for the following cases: inside flow restrictor, with and without offsite power; outside flow restrictor, with and without offsite power. The main steam dump valve opening (credible break) was also analyzed for hot zero power and EOL conditions.

A reduction in core flow will result in a reduction in heat transfer from the fuel to the coolant. Thus the return to power for the MSLB and the return to criticality for the dump valve opening from previous analyses are conservative with respect to the lower flow conditions. However, the MSLB was reanalyzed following conservative feedwater assumptions and Cycle 8 core physics parameters: initial conditions corresponding to hot standby with minimum required shutdown margin at no-load T_{avg}, Cycle 8 core parameters with most reactive control rod stuck in fully withdrawn position; EOL shutdown margin of 1.9% $\Delta\rho$, nominal feedwater flow at full power plus 10% to simulate auxiliary runout flow, and minimum boron injection via the safety injection system.

The analyses showed a minimum DNBR greater than 1.3 for the hypothetical break cases. The core remained subcritical throughout the credible break transient. These results are acceptable for 20% steam generator tube plugging.

12.4.12 Steam Generator Tube Rupture

The impact of plant modifications on the radiological consequences of a steam generator tube rupture has been reviewed. In all cases the transport of radiological materials through the rupture is conservatively bounded by the analysis found in the FSAR. The reactor transient would not be significantly altered by the reduced system flow. In addition, the probability of a tube rupture will not be increased and the potential leak rate would not be increased.

The steam generator modifications do not impede operator control or ability to mitigate the consequences of this event. Therefore, the existing FSAR steam generator tube rupture analysis is not affected by the plant modifications.

13.0 EVALUATION OF OPERATION WITH REDUCED TEMPERATURE

By letter dated April 15, 1981, the licensee submitted "Reload Safety Evaluation, San Onofre Nuclear Generating Station, Unit 1, Cycle 8, Revision 2," dated April 1981.[2] This report suplements the Revision 1 Reload Safety Evaluation dated October 1980. The Revision 2 report proposes the same Technical Specification changes as found in Revision 1. The analyses in Revision 2, which are the same analyses addressed in Revision 1, reflect a better estimate of the steam generator tube blockage and the primary system's flow reduction. The changes between the two revisions are as follows:

	Revision 2	Revision 1
% steam generator tube plugging	15	20
RCS total design flow (gpm)	201,000	195,000
% RCS flow reduction	3.3	6.6
Nominal core T_{in}	528.0°F	551.5°F
T_{avg} @ 100% power	551.5°F	575.1°F
T_{noload}	535.0°F	535.0°F

The licensee will operate at the reduced RCS temperature in order to determine to what extent such reduced temperature operation retards or eliminates corrosion of the steam generator tubes. Since the decision to operate at a reduced core outlet temperature is not based on safety considerations, the unit will be returned to operation at the original core outlet temperature at such time that future circumstances warrant such operation. The licensee is not prevented from returning to normal operating temperatures, since this condition has been analyzed and found acceptable.

The licensee has reexamined all of the previous analyses to verify that the changes in Revision 2 (i.e., reduced RCS temperatures, steam generator tube plugging, and increased RCS flow) will not affect the conclusions made in the Revision 1 Reload Safety Evaluation. A spectrum of LOCA double-ended cold leg guillotine (DECLG) ruptures were analyzed with discharge coefficients (C_D) of 1.0, 0.8, and 0.6.

The analyses show that the limiting break with regard to peak cladding temperature has changed from the DECLG with C_D of 0.6 to DECLG with C_D of 0.8. The peak

cladding temperature of 2272°F at the design peaking factor of 2.89 remains below the 1971 AEC Interim Acceptance Criteria limit of 2300°F.

The limiting overcooling case, the main steam line break, is unaffected by the changes in Revision 2. This is because the limiting MSLB occurs at no-load conditions when the steam generator inventory is at a maximum and the no-load RCS temperature remains the same for Revision 2.

The licensee examined the limiting transients and has determined that the results remain within required safety margins. The variable low pressure trip (DNBR) equation has been reexamined and the licensee has concluded that no changes are required due to the changes in Revision 2. In addition, the licensee concludes that operating at reduced RCS temperatures will not violate Appendix G of 10 CFR 50, Fracture Toughness Requirements.

14.0 SUMMARY OF OPERATION WITH REDUCED FLOW AND TEMPERATURE

We have reviewed the licensee's Reload Safety Evaluation which reflects the Cycle 8 refueling and steam generator modifications. The licensee's submittal discusses the nuclear design, the proposed Technical Specification changes and the reanalysis of the LOCA and non-LOCA transients.

The licensee has shown by the use of conservative assumptions and acceptable analyses that the San Onofre Nuclear Generating Station, Unit 1 can be safely operated with a maximum effective steam generator tube plugging level of 20%. The limiting transients were reanalyzed and the results are within required safety margins. The emergency core cooling system performance has been reanalyzed for the large-break LOCA with the result that the compliance with the Interim Acceptance Criteria is assured. For the limiting case the peak clad temperature does not exceed 2300°F.

The NRC staff has reviewed the licensee's safety analyses and the proposed Technical Specification changes. We find that these analyses have been performed with acceptable methods and assumptions; and that the analyses address all of the potential safety concerns related to the effects of steam generator tube plugging. We also find the Proposed Technical Specification changes acceptable.

The staff has also reviewed the licensee's submittal, "Reload Safety Evaluation, San Onofre Nuclear Generating Station, Unit 1, Cycle 8, Revision 2," dated April 1981.[2] The staff concludes that the changes of Revision 2 regarding the reactor coolant system flow, the steam generator tube plugging, and the reactor coolant system temperature will not affect the conclusions made in the Revision 1 Reload Safety Evaluation, will not result in the loss of required safety margins for the accidents and transients analyzed, and therefore, are acceptable.

15.0 CONCLUSIONS

Based on staff evaluation, we conclude that the San Onofre Unit 1 can be returned to power without undue risk to public health or safety subject to the completion of all proposed repairs, corrective actions, and tests discussed in this safety evaluation. In addition, we find the proposed Technical Specification changes as modified, and agreed upon Technical Specification changes and license condition acceptable.

We have further concluded, based on the considerations discussed above that: (1) because the amendment does not involve a significant increase in the probability or consequences of accidents previously considered and does not involve a significant decrease in a safety margin, the amendment does not involve a significant hazards consideration, (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

16.0 REFERENCES

1. Amendment No. 95 to Docket No. 50-206 submitted via letter from Southern California Edison Company to USNRC (R. Dietch to H. Denton) dated December 10, 1980.

2. Letter dated April 15, 1981, from K. Baskin, Southern California Edison Company to D. M. Crutchfield, NRC transmitting report entitled, "Reload Safety Evaluation, San Onofre Nuclear Generating Station, Unit 1, Cycle 8, Revision 2," April 1980.

3. Letter dated April 10, 1981, K. P. Baskin, Southern California Edison Company, to D. M. Crutchfield, NRC transmitting report entitled, "Steam Generator Repair Program, Return to Power Report, San Onofre Nuclear Generating Station, Unit 1, April 1981" (SG-81-04-006).

4. Letter dated August 29, 1980, from K. P. Baskin, Southern California Edison Company, to D. M. Crutchfield, NRC, transmitting Westinghouse report entitled, "Steam Generator Repair Report, San Onofre Nuclear Generating Station, Unit 1, September 1980" (SE-SP-40(80)).

5. Westinghouse Electric Corporations, "Steam Generator Repair Report, San Onfore Nuclear Generating Station, Unit 1," SE-SP-40(80), Revision 1, March 1981.

6. Letter dated March 5, 1981, from K. P. Baskin, Southern California Edison Company, to D. M. Crutchfield, NRC, transmitting report entitled, "Technical Evaluation Report for a Hybrid Joint, San Onofre Nuclear Generating Station, Unit 1, March 1981," (NS-MFSE-81-054).

7. Westinghouse letter NS-CE-1282 dated November 22, 1976.

8. Section 3A of RESAR-414.

9. Transcripts from the Third Party Design Review of October 23 and 24, 1980.

10. NUREG/CR-0718, "Steam Generator Tube Integrity Program--Phase I Report."

11. Westinghouse Electric Corporation, "Design Bases for the Thermal Overpower ΔT Trip Function," WCAP 8745, March 1977.

12. ECCS Performance Analyses for San Onofre Nuclear Generating Station Unit 1, dated January 31, 1973.

13. ECCS Performance Recalculation, San Onofre Nuclear Generating Station Unit 1, dated December 1976.

14. ECCS Performance Reanalysis, San Onofre Nuclear Generating Station Unit 1, dated May 1978.

15. Letter from VEPCO to USNRC (C. Stallings to E. Case), dated August 9, 1977.

16. NRC Staff Safety Evaluation Report Supporting Amendment Nos. 34 and 35 for Surry Units 1 and 2.