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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 89 TO PROVISIONAL OPERATING LICENSE NO. DPR-13

SOUTHERN CALIFORNIA EDISON COMPANY

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT NO. 1

DOCKET NO. 50-206

1.0 INTRODUCTION

By letter dated April 9, 1985, Southern California Edison Company (the licensee) submitted an application to amend Provisional Operating License No. DPR-13 by revising license condition 3.E., Steam Generator Inspections.

The revised license condition requires (1) during the refueling outage scheduled to begin no later than November 30, 1985, Southern California Edison Company shall perform an inspection of the steam generators, (2) the inspection program shall be submitted to the Commission at least 45 days prior to the scheduled shutdown and (3) Commission approval shall be obtained before resuming power operation following this inspection.

A Notice of Consideration of Issuance of Amendment to License and Proposed No Significant Hazards Consideration Determination and Opportunity for Hearing related to the requested action was published in the Federal Register on May 1, 1985 (50 FR 18587). No comments or requests for hearing were received.

2.0 DISCUSSION

On September 4, 1984, the San Onofre Unit 1 Provisional Operating License DPR-13 was amended to revise Condition 3.E. which requires that a steam generator inspection be performed within 6 equivalent full power months (EFPM) of operation from startup following the 1982 to 1984 extended outage. It is estimated that this inspection would be required by mid to late June 1985, assuming optimum plant operation. The objective of this required inspection is to monitor the condition of the non-sleeved steam generator tubes at San Onofre Unit 1. The time interval for this interim inspection was based upon assigning to the non-sleeved tubes a conservatively estimated intergranular attack (IGA) degradation rate of 15% per year of operation. This previously established 15% per year degradation rate was based on a comparison of historical eddy current data from tubes that were within active regions of steam generator A and were also sleeved during the 1980-81 Sleeving Repair Project.

By letter dated March 19, 1985, the licensee submitted the report "1985 Re-evaluation of Steam Generator Inspection Interval". The purpose of this report was to provide information upon which to establish a revised degradation rate applicable to non-sleeved tubes which more appropriately reflects the rate of progression of IGA among these tubes. The appropriate interval between inspections could then be established, based upon this revised degradation rate. Based on this report, the licensee requested that the steam generator inspection be delayed until the refueling outage scheduled to begin no later than November 30, 1985. The requirements to submit the inspection program 45 days prior to the shutdown and to obtain Commission approval before resuming power operation after the inspection are unchanged.

During the 1980-81 Sleeving Repair Project, it was established that IGA had occurred at the top of the tubesheet in the hot legs of San Onofre Unit 1 steam generators A, B, and C. The regions of aggressive attack were identified using eddy current test data and results of metallurgical examinations of pulled tubes.

Boundaries were then formulated which encompassed these regions, and all tubes within the boundary for each steam generator were sleeved. The regions outside the sleeving boundaries contain non-sleeved tubes. These tubes were not sleeved because analysis of eddy current data collected during the sleeving project yielded no quantifiable indications of IGA at the top of the tubesheet.

In approving the San Onofre Unit 1 return to power operation after the 1980-81 Sleeving Repair Project, a license condition was imposed requiring a steam generator inspection within 6 EFPM after the outage because of the inability of eddy current technique (ECT) to reliably detect and quantify IGA. This inspection was performed in 1982. Current license condition 3.E requires an interim steam generator inspection within 6 EFPM of the outage that ended on November 27, 1984. The limiting condition of a 6 EFPM operating interval was based on the assumption that the depth of IGA penetration could be up to 40% before becoming detectable by ECT. In addition, a tube could have a degradation rate of 15% per 12 EFPM. Under these assumptions, an operating interval of 6 EFPM would limit non-sleeved tube degradation to less than 48% at the first inspection following post-sleeving return to power. This degradation level would, in turn, be less than the plugging limit of 50% for non-sleeved tubes.

3.0 EVALUATION

A revised degradation rate was determined based upon a review of historical eddy current examination data for non-sleeved tubes. Using this data, signals at the top of the tubesheet that were indicative of IGA were re-evaluated. The characteristics of eddy current signals in these non-sleeved tubes, over several inspection intervals, were then compared and contrasted with signals over similar inspection intervals of sleeved tubes which were known to have undergone active degradation due to IGA. From such a comparison, an assessment of IGA progression rate was made for the relatively inactive regions and a revised value for non-sleeved tube degradation rate was established.

Such an assessment relies on a) the capability of eddy current techniques to detect IGA as found at San Onofre Unit 1, and b) the ability to correlate the threshold of detectability with IGA depth of penetration. To this end, in-situ eddy current responses of tubes, subsequently pulled from steam generators A and C during the 1980-81 Sleeving Repair Project, were re-evaluated and compared to the metallurgical results as reported in the 1981 Return to Power Report.

Verification of the assessment of IGA progression in non-sleeved tubes is obtained through the comparison of the results of eddy current examinations conducted in 1982, following approximately 4.3 EFPM of operation with results of inspections of 1984, following an extended shutdown to perform plant modifications.

The assumed degradation rate for non-sleeved tubes is conservative since (1) the rate was derived from tubes inside the sleeving boundary having quantifiable, unambiguous eddy current indications of IGA and (2) the time frame over which IGA was assumed to have progressed from threshold detection levels to quantifiable depth was conservatively limited to the period 1976 to 1980.

The assumption the non-sleeved peripheral tubes have IGA depths near the detectability level of 40% is also a conservatism in the formulation of the operating interval. Eddy current examination results from the 1982 and 1984 steam generator inspections indicate further that this assumption, when considered with an assumed degradation rate of 15% per year, is overly conservative. These inspections showed negligible progression of IGA in the non-sleeved tubes following approximately 4.3 EFPM of operation and 26 months in lay-up conditions. Were the 15% degradation rate applicable to non-sleeved tubes and were the depth of IGA at the 40% level at the time of the sleeving project, then evidence of progression of IGA in non-sleeved tubes would have been evident in the eddy current examination.

The degradation rate applied to non-sleeved tubes prior to return to power in 1981 was developed based on the eddy current responses of 39 tubes in steam generator A, located in active regions within the sleeving boundary. No tube in the group exhibits a normal tubesheet entry signal throughout its inspection history which, in many cases, dates back to 1973. Many tubes in the active regions surrounding the 39 tubes exhibit the same characteristics.

In 1982 following approximately 4.3 EFPM of operation after the 1980-81 Sleeving Repair Project, a comprehensive eddy current examination of sleeved and non-sleeved tubes was performed in all three steam generators. The results showed negligible change in progression of IGA in non-sleeved tubes. In April of 1984, following approximately 26 months in lay-up conditions, the steam generators were again inspected in preparation for return to power scheduled for late 1984. Steam generator A was selected for inspection and both sleeved and non-sleeved tubes adjacent to the sleeving boundary were examined. Results showed no evidence of IGA progression.

Eddy current data from 1973 to 1982 were reviewed and compared to determine the extent to which IGA and "IGA-like" indications have been present and have changed over the years. From the inspections prior to 1980, composite eddy current signatures and horizontal and vertical channels of the 400 kHz differential bobbin coil probe were reproduced using the DDA-4 analysis system. From the 1980 and 1982 inspections, the 400 kHz (1980 only), 340 kHz and 340/100 kHz mix were reproduced as was the 100 kHz absolute. The documented signatures were then sorted into groups of tubes inside and outside the sleeving boundary. The signatures from various inspections of a given tube were compared to determine whether responses indicative of IGA were present and to what extent these have changed.

In reviewing the histories of tubes within the active region, there is evidence, dating back to the 1973 eddy current examination records, of IGA itself or signal distortions which can be attributed to IGA. For these tubes, there is also a consistent, detectable pattern of change toward greater degradation. In the review of non-sleeved tube inspection data, which are below the detection threshold, unlike data from tubes in active regions, no significant changes in eddy current signatures were observed from one inspection to the next. In addition, the review did not identify any discretely quantifiable, unambiguous IGA indications such as those found in the active regions. To estimate the degradation rate of tubes in the "inactive region," degradation data of tubes near the boundary of the "active region" were re-evaluated. Using the data in table 2.1 of the report a degradation rate of 1% per EFPM can be justified.

To confirm the ability of the bobbin coil probe to detect the IGA which has occurred at San Onofre Unit 1, tube lengths were removed from hot leg sides of steam generators A and C during the Sleeving Repair Project. The field eddy current data collected from these tubes prior to removal were re-evaluated and compared to the metallurgical examination results.

The comparisons show that in all cases the 100 kHz absolute bobbin coil detects the IGA condition reported by the metallurgical examination. The results further indicate that the 400 kHz differential bobbin coil exhibits a response to the IGA condition in the majority of cases where the metallurgical examination shows an IGA depth of >40%. Based on the correlation of bobbin coil responses with pulled tube metallurgical examination results, it is concluded that the bobbin coil can detect IGA, as found at San Onofre Unit 1, at levels exceeding 20%.

The data and the licensee's methodology of the re-evaluation of IGA tube penetration have been reviewed by our eddy current inspection consultant, C. V. Dodd of Oak Ridge National Laboratory. He agrees with the licensee's methodology of evaluation and the limits of the historical detectability of IGA penetrations.

Assurance of the continuing validity of the assigned value of degradation rate is supported by our review of the steam generator water chemistry history and controls subsequent to the 1980-81 Sleeving Repair Project. The review indicates that conditions which could accelerate IGA progression in non-sleeved tubes are unlikely to occur. The secondary water chemistry monitoring and control program is consistent with the guidance of EPRI Report NP-2704-SR dated October 1982, "PWR Secondary Water Chemistry Guidelines."

Conclusion

Based on the correlation of 1980 ECT data with the pulled tube metallurgical results, the bobbin coil can be used to detect IGA, as found at San Onofre Unit 1, at levels in excess of 20%. This indicates the conservatism of the detectability threshold of 40%.

The results of the review of historical eddy current inspection data clearly identify the non-sleeved tubes as an "inactive" region of the tube bundle. However, the presence of non-quantifiable "IGA-like" indications in certain non-sleeved tubes indicates that IGA may be present, but based on the detectability threshold discussed above, it is concluded that IGA in the non-sleeved region is not likely to have progressed to levels greater than 40%.

Based on the comparison of historical data, evidence of IGA-like eddy current indications is present in the earliest available inspection data. This would indicate that IGA commenced sometime prior to 1973.

A review of the data show good detectability at IGA levels > 20%, which, when the distorted tubesheet indications are considered, leads to the conclusion that the actual IGA level in non-sleeved tubes is not likely to have exceeded the 20% to 30% level. However, using 1% per EFPM IGA progression rate and conservatively assuming that IGA is near the 40% level in the non-sleeved tubes, eddy current inspections and evaluations at each refueling outage will ensure that tube degradation due to IGA will be detected before it reaches the 50% plugging limit for San Onofre Unit 1 non-sleeved tubes.

Based upon the above considerations and a conservatively assumed IGA level of 40% and a 1% per EFPM degradation rate, it is concluded that there is sufficient margin to the minimum tube wall required for safe operation for the current operating cycle under normal and postulated accident conditions. Therefore, the Southern California Edison request to modify the license condition and to continue operation until shutdown for refueling on November 30, 1985 is acceptable because the plant will have less than 11 EFPM of operating time since the last inspection and the start of power operation on November 27, 1984.

4.0 ENVIRONMENTAL QUALIFICATION

This amendment involves a change in the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that this amendment involves no

significant hazards consideration and there has been no public comment on such finding. Accordingly, this amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

5.0 CONCLUSION

The staff has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (2) 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.

6.0 ACKNOWLEDGEMENT

This Safety Evaluation has been prepared by B. Turovlin and W. Paulson.

Dated: June 5, 1985.