February 24, 1984

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	ASLBP 83-491-04-OLA
(Three Mile Island Nuclear	)	(Steam Generator Repair)
Station, Unit No. 1)	)	

AFFIDAVITS OF

DAVID G. SLEAR
BRANCH D. ELAM
MARY JANE GRAHAM
STEPHEN D. LESHNOFF
F. SCOTT GIACOBBE

IN SUPPORT OF

LICENSEE'S MOTION FOR SUMMARY DISPOSITION OF
EACH OF TMIA'S AND JOINT INTERVENORS' CONTENTIONS

SHAW, PITTMAN, POTTS & TROWBRIDGE

George F. Trowbridge, P.C.
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Station, Unit No. 1)	)	

AFFIDAVIT OF DAVID G. SLEAR

DAVID G. SLEAR, being duly sworn according to law, deposes and states as follows:

1. My name is David G. Slear. I am employed by the GPU Nuclear Corporation as the TMI-1 Manager of Engineering Projects. A statement of my educational and professional qualifications and training is attached and incorporated in this affidavit by reference.

2. I was the OTSG Repair Project Manager for the period from December, 1981, when the tube damage was discovered, through November, 1983. In this capacity, I managed (in conjunction with individual task managers) all aspects of the OTSG Recovery program at TMI-1, including failure analysis, eddy current examination, corrosion testing, RCS examination, RCS sulfur cleanup and plant performance analyses. I directly

managed the OTSG Repair process itself. I was personally involved in making technical decisions regarding the repair process and in defining and implementing the overall project plans and schedule. I have made numerous presentations on the project details to the NRC, ACRS, TPR and GPUN management.

3. The purpose of my affidavit is to address TMIA Contentions 1.a and 1.b. In the course of this affidavit I will provide a brief description of the TMI-1 steam generators, a brief description and history of the steam generator tube cracking which led to the kinetic expansion repair process, and a description of the repair process itself. I will then describe the qualification program for the repair process and the in-process repair testing which have demonstrated that the kinetic expansion joint formed by the repair process fully complies with the original licensing basis requirement for "an extremely low probability of abnormal leakage, of rapidly propagating failure and of gross rupture." And finally, I will describe the post-repair and plant performance testing and analysis, and the special licensing conditions to be imposed by the NRC, which provide additional assurance that the licensing basis criteria have been met.

Steam Generator Description

4. Unit 1 of the Three Mile Island Nuclear Station is a 776 MWe pressurized water reactor having two vertical, straight tube and shell, once-through steam generators (OTSGs). Each

OTSG contains 15,531 Inconel 600 tubes, with a 0.625-inch outer diameter, and a 0.034-inch minimum wall thickness.

5. Each tube is 56 feet and 2 3/8 inches in length. The ends are inserted into holes drilled in two 24-inch thick carbon steel tubesheets at the top and the bottom of the OTSG. The tube is fully inserted, and protrudes about 1/2 inch beyond the upper face of the Inconel clad upper tubesheet and the lower face of the lower tubesheet, into the primary head at each end of the OTSG.

6. There is a nominal 0.005-inch radial gap between the outer surface of the tube and the surface of the tubesheet hole. The tubes are sealed at each end to the tubesheet by rolling to a depth of about 1 1/4 inches, and welding on the primary side of the tubesheet surface. Primary coolant (at a pressure of about 2200 psig) flows within the tubes, and secondary system water and steam (at a pressure of about 950 psig) are heated outside the tubes; thus the tubes, including the seal at each end, constitute part of the reactor coolant pressure boundary between the primary and secondary systems.

Kinetic Expansion Repair

7. Following a plant layup in essentially a cold shutdown condition since early 1979, hot functional testing was performed in August and September 1981, during which the steam generators performed properly. Subsequently, in November 1981, primary-to-secondary leakage was discovered during testing of

the reactor coolant system. Detailed examination by eddy current testing (ECT) revealed defects in the tube walls. Based on the initial ECT examination results, about 95 percent of the defects occurred within the top 7 inches of the upper tubesheet.

8. The tubes were repaired by expanding them within the upper tubesheet to provide a new seal to the tubesheet at a location below where the defects were detected. The expansion closed the nominal 0.005-inch gap between the tubes and the tubesheet. The expansion was done kinetically using explosives (detonating cord) encased in a polyethylene insert. The insert transmits the explosive energy to the tube wall. There is a resulting interference pressure between the tube and tubesheet. The use of kinetic expansions to seal heat exchanger tubes within tubesheets has a broad base of successful experience in heat exchangers such as steam generators.

9. The tubes were expanded from the top of the upper tubesheet down either 17 inches or 22 inches, depending on the elevation of the lowest ECT indication within the upper tubesheet. The expansion length was selected for each tube to provide at least a six-inch ECT indication-free expanded length between the lowest elevation ECT indication and the bottom of the expansion to serve as the new pressure boundary. To accomplish this, tubes having the lowest ECT indication within the uppermost 11 inches of the tubesheet received a 17-inch expansion, and tubes with the lowest ECT indication within the

uppermost 16 inches received a 22-inch expansion. This also resulted in a minimum of two inches between the expanded/non-expanded transition zone of the tube and the lower face of the tubesheet. As a result of standardizing the expansion length, i.e., the 17- and 22-inch lengths, many tubes have an ECT indication-free expanded length greater than six inches.

10. The expansion length was also selected such that there were no ECT indications in the 1/8" to 1/4" transition zone between the expanded and non-expanded portions of the tube.

11. The Technical Specifications of the operating license for TMI-1, which reflect the licensing basis for the OTSG tubes, require that tubes with imperfections equal to or greater than 40 percent of the tube wall thickness be taken out of service by plugging. The repair program at TMI-1 complied with this 40 percent criterion. If a kinetically repaired tube has a 40 percent or greater through-wall ECT defect indication within the pressure boundary, that tube is removed from service by plugging. Thus, the tubes will be in compliance with the OTSG industry standard 40 percent plugging criteria and, assuming the kinetic expansion joint meets the licensing basis for the reactor coolant pressure boundary, the repaired tube will be returned to its original licensing basis.

Licensing Basis

12. The licensing basis for both the original, unrepaired tubes and for the kinetic expansion joint is as specified in General Design Criterion 14, 10 C.F.R. Part 50, Appendix A, i.e., "to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture."

13. With regard to loads that must be sustained by the kinetic expansion joint, the maximum tube load resulting from design basis events for both the original unrepaired tubes and the repaired tubes is 3140 pounds (for a main steam line break accident) and is applied due to axial tension within the tube below the expansion joint. This load is due mainly from tube/steam generator axial differential thermal expansion when the tubes are cooled to a lower temperature than the cylindrical shell of the steam generator. In essence, the tubes tend to thermally contract axially between the upper and lower tubesheets, and this contraction tends to be prevented because the tubesheets are affixed to the steam generator shell. The result is the tubes are axially elongated and an axial tensile load is applied to the kinetic expansion joint.

14. With regard to leakage, including leakage past the kinetic expansion joint, the Technical Specifications for TMI-1 require shutdown if the total leakage for both steam generators exceeds 1 gpm. In addition, the NRC's proposed license conditions for restart with repaired tubes require shutdown if a leakage increase exceeding 0.1 gpm above a pre-established baseline is detected.

Qualification Programs

15. An extensive testing program was conducted to qualify the kinetically expanded joint to the licensing basis. The qualification program has demonstrated that the expansion joint meets the licensing basis, and is at least as effective as the original rolled and welded joint in all relevant respects, including axial loads from the worst case design basis operating and accident conditions, tube preload considerations, and residual stresses in the transition zone.

(a) Axial Loads

16. The expansion joint is required to sustain the maximum postulated loads from a design basis accident, which is an axial tensile load of 3140 lbs. resulting from a main steam line break. Tests were performed on simulated tube/tube sheet configurations to determine the axial load carrying capabilities of the expansion joints. The tests involved pulling kinetically expanded tubes out of simulated tubesheets and measuring the "pullout load" required to initiate slippage between the tube and the simulated tube sheet. The test blocks were thermally cycled to envelop the thermal conditions expected to be experienced by a steam generator in operation. In addition, some tubes were subjected to a series of compression/tension load cycles which enveloped expected reactor operating conditions. All data from the pullout tests indicated that the expanded tubes will have pullout loads significantly in excess of the 3140 lb. axial load requirement (with statistical support

in excess of a 99% confidence level on 99% of the tubes). Pullout loads in excess of the requirement were also confirmed on an expansion pull test performed on a full scale generator at B&W's Mt. Vernon Works. These tests demonstrated that the kinetic expansion process did not adversely affect the strength and dimension of the tubes with respect to their axial load carrying capabilities.

(b) Residual Stresses

17. The kinetic expansion process does not change the strength or dimension of the tubes in any manner which would adversely affect the stress levels seen by the tubes. This has been verified by the qualification program, and concurred in by the Third Party Review Group (TPR) at page 15 of the TPR Report. There the TPR, after noting that if the strength or dimensions of the tubes were changed, the repair process could affect the stress level, concluded that the stress levels are not expected to be significantly affected by the kinetic expansion.

18. The only effect of potential significance in strength or dimension with respect to residual stresses is the formation of the transition zone directly beneath the expansion. To minimize the susceptibility of the transition zone to stress assisted cracking, the repair process was designed to minimize the residual stresses in that area. Analysis indicated that the more abrupt the transition, the larger the stress concentrations. Thus, a number of explosive insert shapes were

evaluated, and the geometry which provided the most gradual transition was used to expand the tubes. This resulted in meeting the design objective of creating a transition zone between 1/8" and 1/4" in length. This is a more gradual transition zone than the original rolled joint employed in TMI-1 and other operating reactors.

19. Tubes in once-through steam generators and in recirculating steam generators which have non-stress relieved rolled expansions have operated without cracking or leaking problems in their transition zones after many years of service. The qualification program has shown that the susceptibility of the kinetic expansion transition zone to stress assisted cracking is about the same or less than the suceptibility of the transition zones for non-stress relieved rolled expansions.

20. The residual stress for kinetically expanded tubes was measured in special test blocks using X-ray diffraction and strain gage techniques. The measured stress intensities were about equivalent to those generally reported in the literature for rolled expansion transition zones.

21. In addition, sample Inconel 600 tubes we: expanded by rolling and kinetic processes in order to compare the resulting hardness and microstructure. The hardening effect on both the inner and outer surfaces of mechanically expanded tubes is more pronounced than in the kinetically expanded tube. Thus, since hardness is an indication of the amount of cold work of the tube material, and since cold work tends to make

the material more prone to stress assisted corrosion cracking, the kinetic expansion may be expected to be less susceptible to stress assisted corrosion cracking than the mechanical expansion.

22. Two corrosion testing programs were conducted to evaluate the susceptibility of the transition zone to stress assisted cracking. In the first program, accelerated stress corrosion cracking tests were performed on kinetically expanded tube/tubesheet mockups. The mockups were tested in an aggressive 10% sodium hydroxide (NaOH) solution at constant potential and destructively examined for stress assisted cracking due to residual stresses from the repair expansion process. Test results show no evidence of any significant cracking of the ID surface in the kinetic expansion joint or transition.

23. The second test was conducted using a boric acid solution containing 1 ppm of thiosulfate and 1 ppm chloride. This level of thiosulfate was utilized because it was shown to produce cracking in highly stressed specimens of actual TMI-1 tube samples. It was therefore felt that if the residual stresses were sufficiently high, that cracking could be expected in this environment. The chlorides were added to provide an additional accelerating effect. Tests were conducted at 170°F and 550°F. Testing was conducted on ten single tube/tubesheet mockups that had been kinetically expanded. These tests have shown no evidence of stress assisted cracking of the ID surface in the expanded region or in other regions either at 170°F or at 550°F.

24. Thus, the qualification programs have demonstrated that the residual stresses and the resistance to stress assisted cracking in the transition zone are consistent with the original design of the steam generators.

(c) Tube Preload

25. During the manufacture of the OTSGs, the tubes were stretched slightly so that they would be under a small axial tensile load of about 65-lbs. with the OTSG at ambient temperature. Although the 65-lb. load (preload) is small in comparison with other operating tube loads, the qualification program evaluated the effect of axial tension preload of the tubes, and changes in the preload. Strain measurements on expanded tubes in laboratory test blocks and in the B&W full scale steam generator indicated a reduction in the preload of less than 30-pounds due to the change in length of the tubing. This would result in a less than 30-pound increase in the maximum compressive load which could be experienced by the steam generator under design basis conditions (heatup to operating temperatures), an insignificant increase compared to the 800 pounds necessary to initiate bowing and the 1025 pounds necessary for lateral tube displacement to contact adjacent tubes (for nominal dimensions).

26. In some cases, the degradation of the tube in the area of the seal weld prior to expansion, allowed the tube to slip down, relieving all or part of the preload in a manner unrelated to tube dimension. These tubes have been evaluated to determine the potential effects of relief of preload.

27. The effects of relieving preload with respect to the limiting transient and accident loads on the tubes were examined. The maximum compressive tube load under FSAR accident conditions is a 620-lb. load associated with a postulated feedwater line break accident. This is less than the approximately 775 lb. generic design basis compressive load conservatively associated with a 100°F/hr. heat-up, which is the limiting case (actual heatups are conducted at rates below 100°F/hr). Loss of preload would add 65-lbs. to the 775-lb. compressive load. Thus, for a tube with no preload, 840-lbs. is the conservative maximum compressive load postulated for normal, transient, or accident design basis conditions. For added conservatism, an evaluation was performed of the ability of a tube to withstand 1025-lbs. of compressive load.

28. The analysis showed that a non-preloaded tube will not be overstressed by the transient load conditions. Buckling does not occur under a 1025-lb. compressive load. Tube bowing is limited by the small clearances of the tube support plate holes. Further, the applied load is secondary in nature; it is caused by thermal differential expansion. This means that as the tube begins to bow under the loading, the magnitude of the load is reduced.

29. The Licensee also examined the magnitude of lateral displacement (bowing) to be expected in a tube loaded compressively to 1025-lbs. The magnitude of the lateral displacement in the 16th span of the tube (underneath the upper

tubesheet) will be the largest since that span is longest. Lateral displacement nominally less than the dimensions of the gap between tubes, even under transient conditions, is expected as a result of the loss of preload. However, even if tubes were to contact each other, no problem is expected. During a heatup transient, flow rates are very low and the time duration is relatively short; no significant tube vibration or wear would be expected during this short period of time.

30. The effects of the change in preload on the natural vibration frequency of a tube were also considered. A non-preloaded tube is expected to have a natural frequency about 15% lower than one preloaded. The effect of this frequency reduction is not significant. The Electric Power Research Institute (EPRI) has reported that other operating plant steam generators have variations in tube frequencies of as much as about 10 to 20% within a single steam generator. In addition, test data reported by EPRI show that another plant operating with similar OTSGs has tube frequencies about 15% lower than expected for TMI-1.

31. Accordingly, the relief of preload experienced on some of the tubes at TMI-1 does not present a safety consideration and has no significant effect on the acceptability of these tubes for continued use within the licensing basis.

(d) Expansion Joint Leakage

32. The original design basis for steam generator tube leakage was to provide generators with no detectable leaks at shipment and to control leakage to an acceptable operating level by monitoring and repair over the 40-year life of the plant. The Technical Specifications will continue to specify an allowable limit of one gallon per minute for operation of the repaired steam generators. In addition, the NRC's special license condition will require shutdown if a leakage increase exceeding 0.1 gpm above a predetermined baseline is detected.

33. Leak rate results of testing on the cycled test blocks varied from 1.18×10^{-6} to 187×10^{-6} lb./hr./tube. If every tube in both steam generators leaked at the maximum rate, the cumulative leak rate would be about one one-hundredth of the Technical Specification limit of 1.0 gpm.

(e) Other Considerations

34. In addition to verification by testing that the kinetic expansion joints fully meet the original licensing basis requirements, there are other features of the kinetic expansion repair joint which provide added assurance of integrity. The more important of these are summarized below.

(i) Although credit is taken only for a six-inch length of kinetic expansion, the expansions are actually either 17 or 22 inches in length. This provides substantial additional load carrying capability, even though there may be defects in the tube above the six inches which formed the qualification basis for the expansion joint.

(ii) Even if the kinetic expansion joint were to slip for a substantial number of tubes during a main steam line break, there would be no significant effect of concern since the joint would still be tight and no significant increase in leakage would result.

(iii) Even if a failure could be postulated within the expansion joint or the transition length below the joint, a "tube rupture" type of event (large leakage) could not occur because the tube would still be constrained by its hole in the upper tube sheet and flow would be limited by the tube-to-tubesheet annulus.

In-Process Repair Testing

35. An inspection and monitoring program was conducted during the repair process to verify that the in-generator expansions conformed to those obtained in the qualification program. The program consisted of video surveillance within the OTSG upper head and measurements of the tube inner diameters by profilometry and by diameter gauging on a sampling basis.

36. Video surveillance of operations during the expansion process were conducted to verify that proper procedures were followed and that the correct tubes were expanded or examined. Random out-of-generator expansions were also conducted to verify that the performance of the explosive inserts had not changed since the qualification program.

37. Profilometry verification sampling was performed on the tubes expanded by the initial charge strength in the first three lots in each OTSG. In addition, random post expansion diameter gauging and depth check samplings were performed.

38. The out-of-generator expansions indicated that the process expansion inserts and detonating materials performed as well as those used in the qualification program. Profilometry and diameter and depth gauge checks showed that the in-generator expansions were within the range of variation the qualification program expansions.

Post-Repair and Plant Performance Testing and Analysis

39. The qualification program, together with the in-process repair programs, as described above, demonstrate that the TMI-1 steam generators have been returned to the original licensing design basis, and therefore provide reasonable assurance that the tubes will not rupture during normal, transient, or accident conditions.

40. Post-repair and plant performance testing and analysis provide additional assurance of the integrity of the repair. As discussed below, the objectives of the post-repair and plant performance testing have all been accomplished.

41. Post-repair and plant performance steam generator testing and analysis of the kinetically repaired tube joints have included both a cold and a hot testing program.

42. The cold leak testing program consisted of bubble testing 100% of the expansion joints to determine if further repair or plugging was necessary. In this testing, the primary side is drained to a few inches above the upper tubesheet, and secondary side water level is lowered and pressurized to 150 psig with an inert gas below the upper tubesheet. Kinetic tube expansions and tubing above the lowered water level are leak tested by visually checking for gas bubbles in the upper head. This is a highly sensitive standard test used in OTSGs to locate leaking tubes and welds in the region within and near the upper tubesheet.

43. In two successive 100% bubble tests, a total of only 26 leaking tubes were found in both steam generators. None of these leaks were determined to be in expansion joints, although four of the leaks were so small that their precise location was not determined.

44. The hot testing program included overall integrated leak tests of the steam generators conducted under hot standby conditions and during heatup and cooldown. These tests also applied axial loads on the kinetic expansion joints.

45. A Kr-85 tracer was injected into the primary system to provide a measurable indication of leakage on a continuous basis. The tracer was injected during the initial heatup to 532°F and 2155 psig in accordance with normal operating procedure. Leak testing was conducted continuously during the following phases:

(a) Operational Leak Test. This test is required by Technical Specifications whenever work has been performed on the reactor coolant system. The pressure in the primary system was raised to approximately 2285 psig, creating a differential pressure between the primary and secondary of approximately 1400 psig. This is expected to be the maximum differential pressure experienced by the repaired tube joints during normal operation.

(b) First Thermal Soak. Conditions were allowed to stabilize at 532°F and 2155 psig for approximately one week, to provide baseline leakage data and to allow monitoring of leakage for trends.

(c) Normal Cooldown Transient. A controlled cooldown was conducted according to normal procedure, at approximately 60°F/hr. for approximately three hours to 350°F. A tube-to-shell temperature difference of about 35°F placed thermal loads on the tubes.

(d) Second Thermal Soak. The reactor coolant system (RCS) temperature and pressure was returned to 532°F and 2155 psig and held there for 11 days. Leakage data was obtained for comparison with the earlier thermal soak, and to monitor for any developing trends.

(e) Accelerated Cooldown. A controlled cooldown was conducted at close to the maximum rate permitted by Technical Specifications, at approximately 90°F/hr. for approximately two hours. This transient was to apply greater

loads to the repaired tubes than the earlier cooldown. A tube-to-shell temperature difference of about 47°F was achieved.

(f) Third Thermal Soak. The RCS temperature and pressure was returned to 532°F and 2155 psig, and held there for approximately 11 days. Leakage data was obtained for comparison with the earlier thermal soaks, and to monitor for trending.

(g) Third Cooldown. During this cooldown, at about 90°F/hr., additional steps were taken to achieve a tube-to-shell temperature difference of about 99°F in the "B" OTSG and 112°F in the "A" OTSG. This transient applied greater tube loads than expected during a cooldown conducted according to normal operating procedures.

46. The hot testing indicated an integrated leak rate for both steam generators of only 1 to 2 gph. Technical Specification limits allow up to 1 gpm (60 gph) for such leakage.

License Conditions

47. In addition to the qualification program, the in-process repair testing, and the post-repair testing and analyses, which demonstrate the adequacy of the kinetic expansion repair joint, the NRC will impose special license conditions requiring additional surveillance and testing during operation. These special license conditions provide added assurance against the possibility of tube rupture. Specifically, if any significant degradation of the kinetic expansion

joints were beginning to occur during plant operation, leakage will increase and the steam generator (and plant) can be shut down, tested and repaired, if necessary.

48. Shutdown for inspection will be required if a leakage increase of only 0.1 gpm is detected. This value is only 0.1 of the Technical Specifications limit for normal plant operation.

49. The plant will be required to be shut down after a short period of operation for performance of a special eddy current test (ECT) program. This testing will be performed 90 calendar days after reaching full power or 120 calendar days after exceeding 50 percent power operation, whichever comes first. The special ECT provides additional assurance that degradation of the kinetic expansion joint is not occurring and going undetected.

50. Licensee will be required to perform its power ascension program at staged intervals, with continuous leak testing and intervals for evaluation of the leakage trends after each stage.

51. Licensee will also be required to report at frequent intervals on its on-going long term corrosion lead testing program. These tests involve corrosion tests of actual TMI-1 tube samples, with specimens representative of both the expanded and unexpanded regions, including the transition zones. The tests are under simulated operating conditions, including water chemistry, and will encompass tube load and thermal cycling

effects. These tests will lead operation of the plant by at least one year.

Tube Ruptures

52. The qualification program, together with the in-process repair testing, has demonstrated that the repaired tubes are in conformance with the original licensing basis. Meeting the design basis provides the same reasonable assurance that tube ruptures will not occur during any postulated operating transients, including those associated with restart, turbine trip at maximum power, thermal shock from inadvertent actuation of emergency feedwater at high power, and rapid cooldown following a loss-of-coolant accident (LOCA). Additional assurance is provided by the post-repair and plant performance testing.

53. The loads on the steam generator tubes have been evaluated for normal operating transients and design basis accidents. The worst case situation is the main steam line break (MSLB) which is conservatively analyzed to result in an axial tension load of 3140 lbs. on the expansion joint. All of the loads experienced by the expansion joint during restart, including those resulting from heatup, cooldown, power escalation, and planned transients during power escalation, are well below the MSLB loads to which the repaired tubes have been qualified.

54. Moreover, the repaired tubes have already experienced, without loss of integrity, loads intentionally imposed during post-repair hot testing equal to or greater than those that will be experienced d..ing restart.

55. Similarly, the loads which would be experienced by the repaired tubes during turbine trip at maximum power, thermal shock from inadvertent actuation of emergency feedwater at high power, and rapid cooldown following a LOCA are all bounded by, and considerably less than, the MSLB loads.

56. A turbine trip at maximum power will result in an automatic reactor trip, and the plant will be stabilized at reactor coolant conditions which are comparable to "hot standby" conditions (RCS temperature at or above 532°F). This results in less tube load than for a design basis cooldown transient. Thus, significant changes in the OTSG shell to tube temperature difference and primary and secondary pressures from the power operating conditions are not produced as a result of a turbine trip.

57. Inadvertent actuation of emergency feedwater (EFW) at high power, i.e., a failure that results in starting of the EFW pumps while the plant is operating normally at high power, will not result in the injection of EFW into the steam generators. The design of the TMI-1 EFW system is such that once the EFW pumps are initiated, the actual flow to the OTSG's is controlled by valves which respond to a flow demand signal generated by the OTSG level control system. The water level in

the OTSG at high power levels is much higher than the OTSG EFW level setpoint at which the EFW flow control valves are initiated to open. The EFW pumps are initiated by signals other than and independent of the OTSG level. Therefore, inadvertant actuation of the EFW pumps will not result in EFW injection into the OTSG and will not result in any change to the OTSG tube stresses.

58. Even if EFW injection into the OTSG were to occur, the resulting thermal stresses would not result in stresses sufficient to cause rupture of the repaired tubes. The location of any thermal shock stress condition, due to impingement of cold water that could occur on a tube that was repaired, would be remote from the repaired portion of the tube (about two feet or greater), and the direct thermal shock stress effects would affect only a portion of the tube. The only effect would be a slight decrease in the average tube temperature. Consequently, only a slight change in tube load would occur, far less than the qualification loads.

59. Rapid cooldown following a LOCA will not result in stresses sufficient to cause a rupture of the repaired tubes. The maximum tube load for a LOCA, including the effects of subsequent rapid cooldown, is 2641 pounds. This is well below the 3140-lb. load for which the repaired tubes have been qualified by testing for the main steam line break condition.

Conclusions

(a) Contention 1.a

60. The extensive qualification testing program demonstrates that the kinetic expansion joint, including effects of the expansion repair process on the tubes, fully meets the pertinent licensing basis requirements such that tube rupture is not likely to occur during normal operating and postulated accident conditions. In addition, the post-repair test program and NRC's proposed special license conditions provide added assurance that any postulated significant degradation will be detected in time so as to prevent tube rupture and to avoid endangering the health and safety of the public.

(b) Contention 1.b

61. Because the kinetically expanded joints, including the effects of expansion on the tubes, fully meet the original licensing basis, and because the new expansion joint is well inside the tubesheet hole where the tight constraints preclude tube rupture and rupture-magnitude leakage, with the added assurance provided by the in-process repair testing, the

post-repair and plant performance testing and analyses, and the additional special license conditions, the kinetic expansion repair process will not increase the likelihood of a simultaneous tube rupture in each steam generator, and thus will not increase the attendant likelihood of requiring the operator to accomplish cooldown and depressurization using at least one faulted steam generator, the likelihood of the occurrence of a sequence of events not encompassed by the TMI-1 emergency procedures, or the likelihood of the occurrence of a scenario during the course of a LOCA which would create essentially uncoolable conditions.

David G. Slear

Subscribed and sworn to before me
this 23rd day of February, 1984

Antoinette Cattolica
Notary Public proved to me the person subscribed to herein on the basis of satisfactory evidence

My Commission Expires:

12/16/85

ANTOINETTE CATTOLICA
NOTARY PUBLIC — CALIFORNIA
CITY & COUNTY OF SAN FRANCISCO
My Commission Expires Dec. 16, 1985

PROFESSIONAL QUALIFICATIONS

DAVID G. SLEAR

WORK EXPERIENCE

Company: GPU Nuclear Corporation

Title: TMI-1 Manager Engineering Projects

Responsibilities: Management of TMI-1 modification, which entails: Management of the $25 million annual budget allocated for plant modification; prioritization of the various phases of plant modification; oversight of the technical adequacy of plant modification and of the components involved in plant modification; consultation regarding problem resolution with respect to matters concerning plant modification; and direct supervision of 16 GPU employees. This position demands constant attention to long term and daily plant modification concerns and an extremely firm grasp of both the technical aspects of TMI-Unit 1 and of the various modes and components of modification available for implementation at TMI-Unit 1.

Dates: 1983 - Present

Company: GPU Nuclear Corporation

Title: OTSG Repair Project Manager

Responsibilities: Management (in conjunction with individual task managers) of all aspects of the OTSG Recovery program at TMI-1 including failure analysis, eddy current testing, corrosion testing, RCS examination, RCS sulfer cleanups, and plant performance analysis. This position involved direct management of the OTSG repair process and personal involvement in the decision making process with respect to the repair program. This position also entailed the definition and implementation of the overall project, and required a broad overview and analysis of the OTSG Recovery program. In his capacity as OTSG Repair Project Manager, Mr. Slear was also called

	upon to deliver numerous presentations concerning project details before the NRC, ACRS, TPR, and the GPU Nuclear Corp. management.
Dates:	December 1981 - November 1983
Company:	GPU Service Corporation
Title:	TMI-1 Manager Engineering Projects
Responsibilities:	Similar to those listed for Mr. Slear's present position including management of a $20 million budget and of project engineering for modifications.
Dates:	1979 - 1981
Company:	GPU Service Corporation
Title:	Preliminary Engineering Manager
Responsibilities:	This position entailed: the analysis and preliminary design of 400 Megawatt combustion turbines and of a 600 Megawatt coal fired power plant; extensive analysis of the reliability and availability of the components to be installed in the prospective power plant; and the establishment of a baseline criteria document for the designated plants including the technical documentation and presentation of the plant design for management review.
Dates:	1978 - 1979
Company:	GPU Service Corporation
Title:	Component Engineer
Responsibilities:	This position entailed: the review of design specifications and technical details of products going into TMI-2, including the steam generators, pressurizer, main

condensors, cooling towers, reactor vessel, and internals; technical consultation and analysis of problems; and review of the contractor's design work on new components going into a plant.

UNITED STATES NAVY NUCLEAR SUBMARINE FORCE OFFICER

Title: Engineer Officer

Responsibilities: This position entailed: essentially primary responsibility and control of the onboard nuclear power plant; control of all engineering sections, command of 4 divisions; and supervision of approximately 55 crewmen.

Dates: 1972 - 1974

Title: Machinery Division Officer

Responsibilities: As Machinery Division Officer, Mr. Slear was responsible for: all mechanical components of the primary and secondary systems of the power plant including the steam generator, reactor, and drive controls; chemistry control of the primary and secondary systems; and the supervision of 15 crewmen. Mr. Slear also served as an Auxiliary Division Officer in charge of non-nuclear life support systems, and as a Communications Division Officer.

Dates: 1968 - 1972

Mr. Slear also attended the Nuclear Power Submarine School from 1966 - 1968, during which time he obtained one year of nuclear power plant training (6 months classroom, 6 months actual plant training) in addition to the submarine qualification program.

EDUCATION

College: University of Oklahoma

Degree: B.S. Mechanical Engineering

Dates: 1961 - 1966

College: Stevens Institute of Technology

Degree: M.S. Mechanical Engineering

Dates: 1974 - 1978

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	ASLBP 83-491-04-OLA
(Three Mile Island Nuclear	)	(Steam Generator Repair)
Station, Unit No. 1)	)	

AFFIDAVIT OF BRANCH D. ELAM, JR.

BRANCH D. ELAM, JR., being duly sworn according to law, deposes and states as follows:

1. My name is Branch D. Elam, Jr. I am employed by the GPU Nuclear Corporation as Manager, Mechanical Components Section, Engineering and Design Department. A statement of my educational and professional qualifications and training is attached and incorporated herein by reference.

2. As Manager of the Mechanical Components Section, I performed technical reviews of certain facets of the steam generator repair project, which included responsibility for the development of the design criteria employed by the contractors in their detailed design efforts related to kinetic expansion and plugging. I was also responsible for reviewing and approving contractor qualification programs for expansion and plugging.

3. The purpose of this affidavit is to address TMIA Contention 1.c, which relates to the ability of the plugs installed on the kinetically expanded portions of the TMI-1 steam generator tubes to hold and give a good seal.

4. Three types of plugs have been used in the upper tubesheet area following kinetic expansion. The first type, a Westinghouse roll plug, is a hollow, cylindrical plug which is inserted in the tube and expanded against the existing tube wall. The expansion contact occurs in the region of the original tube-to-tubesheet mechanical roll. The expansion is produced by mechanically rolling the plug to achieve an interference fit with the tube.

5. The roll plug design had been previously qualified by Westinghouse for use in operating PWR steam generators. The qualification program was supplemented by a specific test program for application to the TMI-1 steam generators, which specifically qualified the plugs for leakage and plug retention capability for both normal operating and accident conditions.

6. The kinetic expansion repair process did not in any way "weaken" the tubes or otherwise adversely affect the retention capability or leak tightness of the fully qualified roll plugs. Following the kinetic expansion, many of the tube ends extending above the top of the tubesheet and the seal welds, where most of the cracking had occurred, were damaged. However, for roll plugs, qualification is based on engagement of the original rolled portion of the tube below the seal weld, and no

reliance is placed on engagement of the tube ends above the seal weld. Prior to plugging, the tube ends were machined off to the top of the seal weld.

7. The only portion of the tube of relevance to plugging integrity is the originally rolled portion against which the plug is rolled. The effect of the kinetic expansion on this portion of the tube was to press the already rolled tube harder against the tube sheet. This would not "weaken" the tube or adversely affect the plug retention or leak tightness capability of the engaged portion of the tube.

8. During the plug qualification program, a test was performed to determine the effect of kinetic expansion on the tube internal diameter as it relates to plug performance. The average difference between pre- and post-kinetic expansion measurement was less than .00034 inch, which is approximately 10% of the actual diameter variation modeled in the overall qualification program.

9. Most of the cracking stopped just below the seal weld before the rolled portion of the tubes began, and hence would not be in the area engaged by the plug. Some cracks were also found at a lower elevation, within the tube rolled region. These cracks were circumferential and of a tight nature, with no evidence of intergranular "branching," i.e., the cracks represented single fracture surfaces. There was no general condition of IGSAC identified in the rolled region.

10. The existence of circumferential cracks in the plug engagement region of the tube has a negligible effect on plug performance. Plug retention capability is proportional to the host area engaged, irrespective of discontinuities, since the plug engages the tube both above and below the crack. The slight decrease in surface area due to the surface area of the crack is insignificant compared to the engagement area. This was confirmed in the qualification test program which included a test specimen with a 360° through-wall circumferential cut in the tube wall.

11. Leak tightness of the plugs installed in leaking tubes was demonstrated by extensive cold and hot post repair leak testing programs.

12. Accordingly, the kinetic expansion repair did not weaken the tubes, and had no adverse affect on the capability of the roll plugs to hold and give a good seal.

13. The other two types of plugs installed in the kinetically expanded tubes are B&W weld plugs. The welded nail head plug is designed to be welded to the original tube-to-tubesheet seal weld, after removal of the damaged tube end by machining. The welded taper plug is welded to the tube sheet cladding at locations where a portion of the tube has been removed for examination or testing. Since neither is bonded to the tube itself, the condition of the expanded tube is irrelevant to the performance of the plugs.

14. Neither the seal weld nor the tube sheet cladding was affected by the kinetic expansion process. The kinetic expansion forces are far below those necessary to disturb either the seal weld or the tubesheet cladding. No evidence of seal weld or cladding damage was found during post-expansion strain gauge testing, post-installation QA weld inspections, or the subsequent hot and cold leak test programs.

15. Accordingly, the capability of the weld plugs to hold and give a good seal is unaffected by the kinetic expansion repair.

Branch D. Elam Jr.

Branch D. Elam, Jr.

Subscribed and sworn to before me
this 23rd day of February, 1984.

Annette M. Longo

Notary Public

My Commission Expires:

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RESUME

BRANCH D. ELAM JR.

SUMMARY OF QUALIFICATIONS

Mechanical engineer with experience in power plant design, particularly nuclear, and project management. Broad knowledge of pressurized water and boiling water reactor, balance of plant, and turbine plant systems. Interface experience with utility and architect engineer organizations. B.S. and M.S. degrees in Mechanical Engineering. Pennsylvania professional registration.

GENERAL PUBLIC UTILITIES, Parsippany, N.J.

Manager, Mechanical Components (12/83 to Present)
(06/81 to 12/82)
Manager, Mechanical Systems (12/82 to 12/83)

Technical cognizance of all mechanical systems and components in Oyster Creek and TMI-1 plants. Technical support in solution of operating and maintenance problems. Development of design criteria for plant modifications. Review of plant operating procedures.

Supervisor, Technical Support and TMI-2 Plant Engineering Director (4/79 to 6/81).

Temporary assignment to TMI-2 accident recovery organization after the March 1979 accident. Provided on-site engineering support to plant operations.

Engineering Manager, Seward 7 Project (6/78 to 4/79).

Project management for new fossil fired power plant.

WESTINGHOUSE ELECTRIC CORP., Pittsburgh, Pa. (8/69 to 6/78)

Various positions of increasing responsibility within the Westinghouse commercial nuclear power plant organization including project engineering, reactor and balance-of-plant systems and components engineering, and piping analysis.

COMBUSTION ENGINEERING, INC., Windsor, Conn. (3/66 to 8/69)

ALLIS-CHALMERS MFG. CO., Washington, D.C. (6/59 to 3/66)

Nuclear power plant systems and component design and testing.

EDUCATION

M. S. Degree in Mechanical Engineering, Stanford University (1965)

B. S. Degree in Mechanical Engineering, and A. B. Degree, Lehigh University (1958)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	ASLBP 83-491-04-OLA
(Three Mile Island Nuclear	)	(Steam Generator Repair)
Station, Unit No. 1)	)	

AFFIDAVIT OF MARY JANE GRAHAM

MARY JANE GRAHAM, being duly sworn according to law, deposes and states as follows:

1. My name is Mary Jane Graham. I have been employed by the GPU Nuclear Corporation as a licensing engineer since January 4, 1982.

2. The Third Party Review group was established by GPU Nuclear to provide an independent and objective third-party evaluation of the kinetic expansion repair process and the suitability of returning the steam generators to operation. In my capacity as licensing engineer for the repair project, I am familiar with, and was responsible for providing the various documents reviewed by both the NRC and the TPR during the course of their respective evaluations of the repair process.

3. The TPR issued its initial report on February 18, 1983. Supplements 1 and 2 thereto were issued on May 16 and December 3, 1983, respectively. The purpose of the supplements

was to take into account Licensee's responses to the TPR's comments in the initial report and to take into consideration additional information not available to the TPR at the time of the initial report.

4. On May 19, 1983, Licensee provided the Third Party Review Group (TPR) with GPUN TDR-388, Rev. 3, which documented Licensee's additional analyses of the stresses in the transition zone. These additional analyses defined the stress states in the transition zone. The TPR was apprised of the results of Licensee's additional analyses, as they were performed, through consultation with TPR members during the interim between the TPR's promulgations of the TPR report and Supplement 1 to the TPR report (TPR Supplement 1), dated May 16, 1983. Section E, Comment 5 of TPR Supplement 1 acknowledges Licensee's determination that the stresses in the transition zone are acceptable, and further acknowledges the TPR's satisfaction with Licensee's resolution of the problem posed by Section E, Comment 5 of the TPR report. TPR Supplement 1 at 7.

This finding was reiterated in Supplement 2 to the TPR report (TPR Supplement 2) dated December 3, 1983, which was issued after TDR 388, Rev. 3 was available to the TPR. TPR Supplement 2 at 2.

5. On September 15, 1983, Licensee's representatives and members of the N.R.C. Staff attended a meeting during which GPUN TDR-388 Rev. 3, was disseminated to the Staff.

6. Licensee has conducted among other things:

a) axial load tests, which demonstrated that the new kinetic expansion joint, the tubing in the transition, and tubing below the joint had the strength to carry all necessary loads;

b) evaluations of residual stresses which included direct measurement of residual stresses, sizing of the transition zone, comparative corrosion testing, hardness tests in the expanded area, surface examinations, and post-expansion profilometry, demonstrating that the material properties, mechanical strength, and small dimensional change of the expanded joints are comparable to those in any steam generator tube-to-tube sheet joint; and

c) evaluations of the axial dimension changes that resulted from the expansion process which ascertained that their effect on preload were insignificant.

The results of these tests were made available to the TPR for its review during or prior to the month of December, 1982. These test results are summarized in the documents referenced in the bibliography attached to the TPR's February 18, 1983 report. In addition, Licensee delivered several detailed

presentations directly to the TPR during which the afore-mentioned tests and evaluations were exhaustively discussed.

Mary Jane Graham

Mary Jane Graham

Subscribed and sworn to before me
this 24th day of February, 1984.

Pamela Downer

Notary Public

My Commission Expires:

April 30, 1986

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	ASLBP 83-491-04-OLA
Three Mile Island Nuclear	)	(Steam Generator Repair)
Station, Unit No. 1)	)	

AFFIDAVIT OF STEPHEN D. LESHNOFF

STEPHEN D. LESHNOFF, being first duly sworn, deposes and says as follows:

1. My name is Stephen D. Leshnoff. I am a mechanial engineer employed by GPU Nuclear Corporation, Engineering and Design Department. A statement of my professional and educational training and experience qualifications is attached and incorporated herein by reference.

2. The purpose of this affidavit is to respond to TMI Contention 1.d as it relates to stress and crack propagation analysis in the steam generator tubes. I performed the fatigue evaluation of the TMI-1 once-through steam generator (OTSG) tubes using the methods of linear elastic fracture mechanics. I also participated in other steam generator mechanical analyses, including the determination of leak rates from a through-wall crack.

3. Many of the tubes located in Licensee's OTSG's have suffered some degree of circumferential cracking representative of IGSAC.

4. Licensee has performed many tests and evaluations employing various analyses to document the various properties of the cracks present in the OTSG tubes. The analyses for crack resistance, i.e., for the mechanical propagation of fatigue cracks in the tubes, were not a part of, and are unrelated to, the evaluation of the kinetic expansion repair technique.

5. Axial symmetric (i.e., axisymmetric) analyses were not utilized when evaluating crack propagation because cracks are not assumed to propagate in an axisymmetic manner. The use of axial symmetry in stress analyses means that the stresses on the tubes, not the crack propagation, are axisymmetric.

6. Axisymmetric analyses were only used in one structural evaluation of the tubes. This evaluation was to compute the stress increase in the transition region of the kinetic expansion joint between the expanded and non-expanded portions of the tube. Axisymmetric analysis was appropriate for this evaluation because stresses are uniform around the tube circumference, i.e., bending effects are negligible. This evaluation was not related to Licensee's evaluations of crack propagation.

7. All tube structural analyses performed to evaluate the effects of cracks employed asymmetric analysis for the consideration of nonuniformities in stress distribution around the circumference of the tube.

8. Crack resistance was analyzed on the basis of "toughness," which was factored into the fatigue model to evaluate the effects of stress intensities on crack propagation. Stress intensity is a mathematical representation of the way stresses concentrate at the crack tips when they are transmitted around the perturbation in the stress field caused by the crack. If the stress intensity is very low, the material at the crack tip can strain to accommodate the additional loading, and no crack growth occurs. The threshold stress intensity is the value below which no growth occurs. If the stress intensity is very high, the material will fracture because the material's microstructure cannot accommodate the strain. The lowest stress intensity which results in this fracturing of a material is its "fracture toughness." In general, the more ductile the material, the higher the fracture toughness.

9. Hardness, on the other hand, is not germane to a mechanical crack propagation analysis, and was not used for that purpose. A hardness test was used solely to facilitate a comparison between rolled expansion and kinetic expansion to determine relative susceptibility to IGSAC.

10. Licensee accounted for both large and small cracks in its propagation analysis. In evaluating crack propagation under normal and anticipated transient loadings, a spectrum of crack sizes were interacted with the tube stresses to determine the number of cycles required to propagate the crack through the tube wall. Stress intensities were calculated for partial

through-wall cracks, combining components due to membrane stress, bending stress, and stresses due to internal pressure acting on the parting crack faces, including the thermally induced axial loads constituting the major part of the load cycling. The stress intensity was recalculated for each cycle and the increment of crack growth determined. The new crack length was then used to determine the stress intensity of the next cycle.

11. Smaller cracks grow faster on a percentage basis (i.e., growth per cycle divided by crack size) than larger cracks, if the same stress intensity is applied to both. Therefore, in analyzing the spectrum of crack sizes, stress intensity was separately calculated for each load cycle and crack size was accounted for during that cycle. Accordingly, the effect of crack size was appropriately considered in the fracture mechanics calculations relative to the effects of thermal stress.

Stephen D. Leshnoff

Stephen D. Leshnoff

Subscribed and sworn to before me
this 23rd day of February, 1984.

Notary Public

My Commission Expires:

PERSONAL PROFILE

STEPHEN D. LESHNOFF

52 Park Avenue
Caldwell, New Jersey 07006

EXPERIENCE

Company: General Public Utilities
Nuclear Corp.
100 Interpace Pkwy.
Parsippany, N.J. 07054

Title: Senior Engineer, Grade II

Dept.: Engineering

Duties: Staff Engineer specializing in Fracture Mechanics, Fluid/Structure Interactions, Plant Operations Support, Training

Dates: 12/82 - Present

Company: GPU Nuclear
Oyster Creek Nuclear
Generating Station
Forked River, N.J.

Title: Shift Technical Advisor

Dept.: Operations

Duties: Shift Technical Advisor at Oyster Creek Nuclear Generating Station providing technical evaluation of plant status in the Control Room.

Dates: 9/80 - 12/82

Company: GPU Service Corp.
100 Interpace Pkwy.
Parsippany, N.J. 07056

Title: Senior Engineer, Grade I

Dept.: Engineering

Duties: Engineering support to Fossil Electric Generating Plants, in particular, steam turbine operation and reliability and steam boiler maintenance.

Dates: 9/78 - 9/80

Company: Foster Wheeler
Energy Corp.
Livingston, N.J. 07039

Title: Senior Design
Engineer

Dept.: Fossil Steam Generation

Duties: Design of Fossil Steam Generators and engineering solution to field problems.

Dates: 8/74 - 8/78

Company: Westinghouse Electric Co.
Turbine Divisions
Lester, Pa.

Title: Design Engineer

Dept.: Design Engineering

Duties: Mechanical Design of Steam and Gas Turbines. Awarded three U.S. patents.

EDUCATION

College: University of Pennsylvania, Philadelphia, Pa.

Major: Mechanical Engineering

Degree: B.S.M.E.

Dates: 9/62 - 5/66

College: Rutgers University, New Brunswick, N.J.

Major: Physiology & Biophysics

Degree: M.S.; Ph.D. Candidate

Dates: 9/72 - 5/74, F/T; 1977, P/T

ADDITIONAL EDUCATION

College: Columbia University, New York, NY

Course of Study: Graduate engineering work in chemical reactor kinetics

Dates: 1978 P/T

APPLICABLE ADDITIONAL SKILLS

1. Licensed Professional Engineer, PE-030059. Commonwealth of Pennsylvania.

2. Member, Special Working Group on Operating Plant Criteria, A.S.M.E., Sect. XI, In-Service Inspection of Nuclear Power Plant Components.

3. Shift Technical Advisor. Involves 80-90 hours/month on duty or in training classes.

PATENTS

Three U.S. Patents 3,857,649 3,864,056 3,910,716

PUBLICATION

S. Leshnoff and F. Erdogan, "Mechanical Integrity Analysis of Three Mile Island, Unit #1, Once Through Steam Generator Unplugged Tubes," Journal of Nuclear Engineering and Design, NED 983, in press.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	ASLBP 83-491-04-OLA
(Three Mile Island Nuclear	)	(Steam Generator Repair)
Station, Unit No. 1)	)	

AFFIDAVIT OF F. SCOTT GIACOBBE

F. SCOTT GIACOBBE, being duly sworn according to law, deposes and states as follows:

1. I am presently Manager, Materials Engineering and Failure Analysis for General Public Utilities Nuclear Corporation. A statement of my qualifications and experience is attached and incorporated herein by reference.

2. The purpose of this affidavit is to address the issues raised by TMIA in Contentions 2.a, 2.b.1, 2.b.2 and 2.c, and those raised by Joint Intervenors in Contentions 1(2), 1(3) and 1(5).

I. TMIA'S CONTENTIONS 2.a and 2.c AND JOINT INTERVENORS' CONTENTION 1(5)

3. TMIA's Contention 2.a and Joint Intervenors' Contention 1(5) both allege that Licensee has failed to properly identify the cause of the intergranular stress assisted cracking (IGSAC) which occurred in the TMI-1 OTSGs. TMIA's Contention 2.c raises alleged inconsistencies between the Third Party Review Group report and the NRC Staff's SER concerning the cause of the IGSAC. My response to these contentions follows.

A. INTRODUCTION

4. Subsequent to the discovery of leakage in the TMI-1 once-through steam generator (OTSG) tubing, Licensee developed and implemented an elaborate series of evaluation programs to identify the extent and cause of tube failure. The initial programs were conceived to provide preliminary information as to the location and type of defects present in the tubes, with subsequent chemical analysis of the tube surface film. Additional, broader-scoped analyses to identify and characterize the root cause of failure were developed and implemented once the initial evaluation was completed.

B. PRELIMINARY INVESTIGATION

5. When OTSG tube leakage was first discovered at TMI-1 in November 1981, eddy current testing (ECT) was performed to determine how many tubes were leaking and at what locations.

Initial eddy current results showed that most indications occurred in the upper tubesheet region.

6. In order to corroborate the existence of defects at the locations of eddy current indications, four tube samples were removed from the OTSGs. Examination of these samples visually, by metallography and by electron microscopy determined that the defects were circumferential cracks which were intergranular and inside diameter (ID) initiated. Additional tube samples were then pulled and examined in the same fashion. All exhibited these same characteristics.

7. With this initial evidence, that is, an orientation specific defect and intergranular morphology, it was apparent that we were primarily dealing with an intergranular stress assisted cracking (IGSAC) failure mechanism. Knowing this, energy dispersive x-ray analysis (EDAX) was performed on both inner surfaces and crack fracture surfaces to ascertain the presence of any corrodants. This analysis method is sensitive to all elements above atomic number 10 (Neon) in concentrations above 1 weight percent. The EDAX analysis detected sulfur, chlorine, nickel, chromium and iron. Nickel, chromium and iron are the major alloying elements in Inconel 600; sulfur and chlorine are contaminants which are known to cause IGSAC. A sodium azide test was also performed on both tube surfaces and fracture surfaces. It indicated that reduced forms of sulfur (e.g. sulfide) were present.

C. FAILURE ANALYSES

8. Based on the preliminary investigation which showed that the failure mechanism was some form of IGSAC, our investigation program broadened to include the conditions which must be present for IGSAC to occur. There are three such conditions: First, the material must be in an environment which contains a chemical specie(s) (causative agent) that will cause this type of crack. Second, the material must have a tensile stress applied to it. Third, the material under consideration must be susceptible to this type of environment.

9. Two independent laboratories, Battelle Columbus Laboratories and Babcock & Wilcox (B&W) Lynchburg Research Center, were retained and given the assignment to examine the evidence anew and in-depth, and to develop a root cause failure analysis. Licensee removed a total of 28 tubes for use in these analyses. On the basis of their independent examinations of these tubes, both laboratories produced an in-depth characterization of the cracking morphology. They each also identified and analyzed any form of surface attack which was present and evaluated fracture and tube surface film composition and material properties. Finally, they each provided a description of the failure scenario which they believed was responsible for the damage observed, based on the facts uncovered. The results and conclusions of these two independent analyses were in agreement in all material respects.

D. DETAILED INVESTIGATION OF THE CONDITIONS WHICH COULD HAVE CAUSED THE IGSAC

(1) Aggressive Environment

10. The analysis of tube surfaces performed during the detailed investigation was of course more sensitive than that performed during the preliminary investigation; both Auger Electron Spectroscopy (AES) and Electron Spectroscopy for Compound Analysis (ESCA) were performed. Both these analyses are sensitive to all elements except hydrogen and helium and to levels of 0.1 atomic percent and above. An ion sputtering process was used to strip away the tube surface oxide, layer by layer, in order to measure the precise amount of each substance present at any given depth of the film.

11. Sulfur was detected in the form of both sulfate and reduced forms (primarily sulfides), on both the tube films and the films on fracture surfaces. On the tube itself, up to 1.5 atomic percent of sulfur was detected. On fracture surfaces this level was as high as 8 atomic percent. At the outer surface of the tube films, nearest the atmosphere, the sulfur tended to be in the form of sulfates. Deeper into the film, approaching the tube surface, the predominant form of sulfur was sulfide.

12. Low levels of chlorides were also found on the surfaces of these tubes. Chloride levels were less than 1 atomic percent at the very tops of the tubes where the most extensive cracking occurred. A maximum of 1 atomic percent of chloride

was also found on the fracture surfaces of tubes. After removal of the top layer and proceeding into the film a short distance, the chloride level dropped to where it was non-detectable. (The corresponding sulfur level at this location on this tube film was between 6 and 8 atomic percent.)

13. Carbon was typically detected on the tube surface films as well. At the outer surface, 50 to 60 atomic percent of carbon generally was present. The carbon level quickly dropped to 20 atomic percent or below when the outer layer of the surface films was stripped away by use of the ion sputtering process. The carbon form was determined to be the graphitic or long chain hydrocarbon form.

14. The extensive tube surface analysis did detect other elements in trace amounts, but none were known to cause IGSAC or to have a synergistic influence on that process.

(2) Stress

15. There are several sources of loads on the OTSG tubes, depending on the particular operating conditions of temperature, pressure and unit load. When the OTSG was fabricated, the tubes were installed with a specified amount of tensile preload. This tensile preload remains when the OTSGs are in the cold condition.

16. During heatup and cooldown of the OTSG unit, axial loads are developed in the tubes. During heatup the thick OTSG shell heats and therefore expands more slowly than the tubes. As a result, the shell tends to restrain the tubes' growth, and

the tubes see a compressive load component. In cooldown the opposite condition occurs. The tubes cool more quickly than the shell, and concomitantly contract more quickly than the shell. This results in a net tensile load on the tubes.

17. The action of primary system pressure primarily causes a circumferential or hoop tensile load induced by the primary pressure.

18. These above loads are the principal contributors to the stress state of the tubes. The net tube stress at any time is the sum of all the stresses experienced by tubes. For various operating modes the dominant loads contributing to net stresses can be described as follows: when the unit is pressurized, primary system hot, small axial tensile or compressive loads may be present, however, by far the largest load will be the hoop tensile component. Similarly, during unit heatup there will be a small axially compressive component of the loading on the tubes, but since the primary system is pressurized, the hoop tension is the largest load component. During cooldown, pressure (and the associated hoop stresses) decrease while the temperature change causes the axial tensile load to increase. The largest tube stress will therefore be in the axial tensile direction. At shutdown, since the primary system is depressurized, the only significant load is the axial tensile preload.

19. The cracking of the TMI-1 OTSG tubes was found to be almost exclusively circumferential. Because stress assisted

cracking always produces cracks perpendicular to the tensile stress, this orientation of the cracks implied that the stresses causing the cracks here were axial, rather than in the circumferential or hoop direction. This condition occurs during cooldown and cold shutdown.

20. Vertical cracks were observed only at the tube ends. This orientation is expected since the tube ends are subject only to residual circumferential stresses produced by the weld joining the tube to the tubesheet. These residual stresses are (by definition) always present.

(3) Material

21. In order to completely characterize the metallurgical condition of the TMI-1 tubes, an evaluation of the tubing fabrication history was performed. This evaluation included a review of the tube manufacturing process, mill test reports, and steam generator fabrication process (including stress relief heat treatments occurring during the process), and an identification of the locations of the various heats of tube material in the steam generator.

22. The Inconel 600 tubing used in the TMI-1 OTSGs is typical of the material class and condition of tubing used in most pressurized water reactors in the United States today. Inconel 600 was chosen because of its good corrosion resistance under many corrosive conditions, e.g., caustic corrosion, including chloride-induced corrosion. It is, however, possible to create a set of atypical environmental conditions during which Inconel 600 is subject to corrosion damage.

23. Licensee's research on the tube fabrication process revealed that during the mill anneal process, the tubes probably reached a temperature at which a significant portion of the carbon present in the base metal was put into solid solution in the Inconel matrix. After tube installation in the OTSGs, the entire assembly was heat treated for stress relief. At stress relieving temperatures, some of the carbon which was dissolved during the mill anneal combined with chromium in the Inconel, and these chromium carbides precipitated at the Inconel grain boundaries. This resulted in sensitization of the metal alloy (typical of all OTSGs), which provides the necessary susceptibility to the IGSAC observed in the tubes.

(4) Analysis of Plant Conditions

24. After establishing that the IGSAC initiated from the primary side and that sulfur, perhaps coupled with chloride, were possible causative species, plant operational and chemistry data were reviewed to determine when the attack could have occurred and how the necessary conditions could have been established.

25. Hot functional testing of the entire TMI-1 RCS system was performed in August and September 1981. During hot functional testing, when both the primary and secondary systems were at operating conditions, no leakage was observed. Thus, the cracking would have to have occurred between the end of the hot functional tests and the time the leaks were discovered in November 1981. This relatively short time span is consistent

with the rapid cracking behavior of the observed IGSAC. More specifically, the circumferential orientation of the cracks indicated that the damage occurred during the cooldown and subsequent shutdown following the hot functional testing when the requisite axial loads would have been present.

26. After some attempts had been made to remove impurities from the reactor coolant water in December 1981, analyses of the reactor coolant water samples found measurable levels of sulfate; 700 parts per billion (ppb) were analyzed in the decay heat system. Sulfur is not normally expected to be found in the RCS. Low levels (less than 100 ppb) of chlorides and fluorides were found as well.

27. An investigation of plant chemistry records showed that sulfuric acid was inadvertently added to the reactor coolant system in October 1979. Oil may have also been introduced in small quantities in late 1979. In addition, unexpected changes in reactor coolant conductivity occurred in July 1980 and May 1981. The ionic species most likely to trigger these conductivity changes was sodium thiosulfate (a reduced form of sulfur), which could have been inadvertently introduced into the reactor coolant system from the sodium thiosulfate storage tank during testing of the reactor building spray system.

28. In all these instances, most of the sulfur would have been removed by demineralization of the reactor coolant, but laboratory studies showed that 1-2 parts per million (ppm) of

thiosulfate may have remained from the May 1981 injection in the reactor coolant in August 1981 before the hot functional test. Concentrations of thiosulfate are believed to have reached 4-5 ppm during hot functional testing. This was due to additional testing which resulted in the introduction of sodium thiosulfate via the Borated Water Storage Tank.

29. The levels of chlorides were also examined. To prevent stress corrosion of stainless steel materials in the reactor coolant system, chlorides are limited to less than 500 parts per billion during shutdown and 100 parts per billion during hot operations. There was no evidence that these limits had ever been exceeded. These specified limits are well below the level at which chlorides have been known to cause stress corrosion cracking of stainless steels; sensitized Inconel 600 is considered to be even more resistant to chloride-induced stress corrosion cracking.

30. Operational history was also reviewed to establish when and how the necessary oxygen to allow IGSAC could have been introduced to the reactor coolant system. During the 1981 hot functional test at TMI-1, the system would have remained essentially deoxygenated. Toward the end of the testing, however, a test of the high pressure injection system resulted in the introduction of approximately 15,000 gallons of water that was probably oxygen-saturated to a level of about 8 parts per million. When mixed in with the deoxygenated primary coolant, this would have resulted in a concentration of approximately 2 parts per million oxygen.

31. Additional oxygen would have entered the system during the cooldown after the hot functional test, because the primary system was vented to the atmosphere, and oxygen from the atmosphere would have dissolved in the coolant. At this time the reactor coolant system was at a temperature of about 135°F. Thus, sufficient oxygen and sufficiently low temperature for sulfur-driven IGSAC existed in the RCS during cooldown following the hot functional test.

32. The tube failure pattern detected by ECT suggested that the right combination of conditions to cause IGSAC only existed at a specific location in the OTSGs. Most of the IGSAC was located within the upper tubesheet area (top 24 inches of the tubes), primarily in the top few inches.

E. LITERATURE SURVEYS

33. Concurrent with the failure analyses, Licensee requested the Electric Power Research Institute (EPRI) to conduct a review of the available literature on stress corrosion cracking of Inconel 600. EPRI concluded that sensitized Inconel 600 was susceptible to rapid IGSAC in the presence of metastable sulfur species; and that, in fact, metastable sulfur was the only corrodant known to cause IGSAC at low temperatures. The IGSAC occurs under oxidizing conditions, when sulfur species in intermediate oxidation states, such as thiosulfate and polythionates, are present. In the literature we have found that aggressive sulfur species are variously described as

metastable, intermediate, polysulfur and reduced sulfur (excluding sulfide).

34. Several other failure analyses were reviewed to consider possible effects of carbon on IGSAC. These analyses included tubes examined by different laboratories, from both once-through and recirculating type steam generators, and various tube failure modes including IGSAC, pitting and mechanical failure. In all instances, the only form of carbon found to cause intergranular attack was in the form of sodium carbonate. This requires very specific conditions of high pH (typical of secondary side water chemistry), high temperature, and presence of sludge deposits. Under these specialized conditions, sodium carbonate can hydrolyze and result in the local generation of sodium hydroxide. This leads to a caustic induced intergranular type of attack.

35. No evidence of carbon in the form of carbonates was found on TMI-1 OTSG tube samples. Instead, the carbon form found on the TMI-1 tube surfaces was a graphitic, or long chain hydrocarbon, type of carbon. This form of carbon has not been found to cause intergranular stress assisted corrosion.

36. Although chlorides were detected on the fracture surfaces, GPUN concluded from review of the literature and from conclusions drawn by other investigations that chlorides by themselves could not have caused the IGSAC. One reason why Inconel 600 was originally selected for nuclear steam generator tubes was its high resistance to chloride-induced stress corrosion cracking.

F. DEVELOPMENT OF THE FAILURE SCENARIO

37. The review of TMI-1 operational records, the literature surveys concerning IGSAC of Inconel 600 and the results of the independent failure analyses indicated conclusively that the IGSAC was sulfur-induced, and ruled out all other known possible sources of the cracking. A failure scenario was developed on the basis of the evidence described above, which established the sequence of sulfur introduction and unit operations that resulted in the generation of sufficient quantities of aggressive sulfur species, under the required environmental conditions, to cause the observed IGSAC of the TMI-1 OTSG tubes.

38. IGSAC of the TMI-1 OTSG tubes was determined to have occurred through the following sequence. First, sulfur compounds, primarily sodium thiosulfate, were accidentally introduced to the reactor coolant system via the transfer of sodium thiosulfate-containing water from the reactor building spray system to the borated water storage tank. Sulfuric acid and oil may also have contributed to the sulfur inventory.

39. During the 1981 hot functional test, the combination of reducing (deoxygenated) conditions and high temperature caused the thiosulfate species to transform toward more reduced metastable species. The cracking did not occur at this time, however, because oxygen was not present in the system.

40. Late in the hot functional test sequence, reactor coolant conditions became oxidizing. This was due to a

combination of (1) direct injection of a relatively large volume of oxygen saturated water from the Borated Water Storage Tank and (2) venting to the atmosphere on cooldown. The oxidizing conditions in the presence of relatively high concentrations of aggressive metastable sulfur species led to the IGSAC.

41. The combination of factors most favoring cracking occurred in the upper tubesheet region. At this location, the tubes are subjected to high residual stresses due to the tube-to-tubesheet welds and tube rolling. Oxygen introduced during system venting would also be concentrated in this region because of the vapor space resulting from the lowering of the water level. Moreover, this vapor space caused the sulfur to concentrate on the tube surfaces in the upper tubesheet region.

42. The environment in the OTSGs was dynamic during cooldown from the hot functional testing. Oxidizing potential and water level were changing. Under these conditions some individual tubes below the upper tubesheet experienced cracking conditions long enough to cause the widely scattered IGSAC seen in the lower elevations.

43. The continuing change in conditions also caused termination of the cracking. As time allowed the further oxidization of polysulfur species, the presence of an aggressive intermediate sulfur species became less probable. The combination of this change in conditions with other dynamic changes, such as dilution of surface films by the bulk OTSG water, caused the cracking to terminate.

G. TESTING TO VERIFY THE FAILURE SCENARIO

44. Several short term corrosion testing programs were performed by B&W and Oak Ridge Laboratories, another Licensee consultant, to verify that the observed IGSAC could be caused by the action of sulfur species during cooldown or shutdown from hot functional tests.

45. When the first tube samples were removed from the TMI-1 OTSGs, a tube section which contained a defect detected by eddy current was tested to determine whether the reactor coolant was still aggressive. The tube was placed in actual reactor coolant water and loaded to representative tube loads. No propagation of the cracking occurred.

46. A further test series determined the susceptibility of the OTSG tubing to various aggressive species which could have caused the cracking. Actual tubing removed from the OTSGs was found to be susceptible to IGSAC in simulated reactor coolant containing from 1 to 5 ppm of sodium thiosulfate. However, no cracking was detected in coolant containing up to 10 ppm of either sulfate or chlorides.

47. A series of tube samples were then exposed to sodium thiosulfate as a corrosive agent. These samples used sensitized archive OTSG tubing which was loaded axially. The corrosive solution, consisting of 100 ppm sodium thiosulfate, in synthetic primary coolant, was introduced to the inside of the tubes. Through-wall circumferential cracks grew in the tubes. Although these tests were designed to provide verification of

the eddy current test procedures, they also provided support for the failure scenario; based on metallurgical examination, the morphology of this cracking was identical to the intergranular cracking observed in the actual OTSG tubes.

48. The two testing laboratories also performed tests which duplicated the time and temperature sequences of hot functional testing. Actual Inconel 600 tubes which had been removed from the TMI-1 OTSGs were used. The tests showed that 5 ppm of sodium thiosulfate was sufficient to cause cracking of specimens stressed to above yield strength, but did not cause cracking of specimens stressed at lower levels. One ppm thiosulfate during these test series did not cause cracking of even the most highly stressed specimens.

49. Both high and low temperature tests were performed on actual OTSG tubing specimens that had been subjected to repair and hydrogen peroxide cleaning processes. These tests used reactor coolant chemistry water with 1 ppm each of chloride and thiosulfate. No initiation or propagation of IGSAC on the tube ID was found during these tests.

50. A limited number of tests were performed to determine the effect of the test solution temperature on IGSAC susceptibility. TMI-I archive tubing was exposed for 740 hours to borated water with 10 ppm thiosulfate at 100°F and did not fail. However, this material exposed to the same environment but at 170°F produced small amounts of IGSAC in 113 hours. Further tests were performed at 250°F in an autoclave. No attack was

observed after 168 hours. From these tests and those of other investigations there appears to be a temperature near 170°F at which stress relieved Inconel 600 is most susceptible to thiosulfate induced IGSAC. At temperatures above this, the cracking propensity is reduced and ultimately inhibited.

51. These tests, taken as a whole, confirmed that sodium thiosulfate in the concentrations that could have existed in the TMI-1 reactor coolant system was capable of causing IGSAC during cooldown or shutdown periods; they also confirmed that sulfate or chloride at levels significantly higher than what was present in the TMI-1 RCS were <u>not</u> capable of causing the corrosion.

H. SPECIFIC POINTS RAISED BY INTERVENORS

(1) <u>Mechanism and Form of Sulfur</u>

52. In their responses to interrogatories posed by Licensee, the intervenors rely on the following statements to support their contentions that a causative agent other than sulfur could have caused the observed IGSAC:

(a) That the NRC Staff states at page 8 of the SER that the failure scenario "has not been clearly established" (TMIA 1st Resp., to Interrog. 2.a-1);

(b) That Mr. Dillon commented on apparent "inconsistencies in the cracking environments" which "certainly invite questions" (<u>Ibid</u>.); and

(c) That Dr. MacDonald stated that another polysulfur species must be present in the system, [and] that sulfur deposits of an unknown form were observed in the system (<u>Ibid</u>; see also J.I. 1st Resp., to Interrog. 1(2)-5).

53. I should first say that the NRC Staff did not question the failure scenario, as alleged. The Staff noted that the "specific mechanistic steps" involved in the cracking phenomenon, i.e., the individual chemical reactions involving the various metastable forms of sulfur present at the time of the cracking during the transition from oxidized to reduced states, has not been definitely established. That is the basis also for the statements of Dillon and MacDonald. Licensee agrees with this conclusion. This does not, however, cast doubt on the cause of the cracking or Licensee's ability to control its recurrence, and neither the Staff nor its consultants so suggest.

54. Licensee-sponsored test programs have established that IGSAC of the same morphology as seen in the TMI-1 OTSG tubes can be caused by sodium thiosulfate under conditions of temperature and oxidizing state that existed in the OTSGs in the cooldown following hot functional testing. Knowledge of the corrosive elements and environmental conditions that cause IGSAC is sufficient to ensure that the control strategy will prevent reinitiation of IGSAC; not defining the specific mechanistic steps does not invalidate the approach.

55. The first emphasis of the control strategy is to control the total amount of sulfur in the reactor coolant system. Initially, sulfur was removed through ion exchange and chemical cleaning. Periodic analyses of reactor coolant for sulfates will ensure that the total amount of sulfur in the reactor

coolant system is well below that level where it can be harmful. Operational controls will prevent the combinations of temperature and oxiding conditions which result in the conversion of relatively harmless sulfur forms to potentially harmful sulfur forms. The long term corrosion tests and the hot functional testing of the plant establish that corrosion will not reinitiate under these controls. Therefore, the modifications which have been made to the system environment and the operational controls to prevent reinitiation of IGSAC will be effective <u>regardless</u> of the specific mechanism and form of sulfur involved in the IGSAC process.

56. In a related vein, TMIA has claimed that the SER recognizes three contaminations, which may have caused corrosion, and asserts this supports its Contention 2.a. <u>See</u> TMIA 1st Resp., to Interrog. 2.a-1. However, the discussion in the SER cited by TMIA concerns possible previous contaminations which may have contributed to the total <u>sulfur</u> inventory present after hot functional testing -- these contaminations did not themselves cause corrosion. Thus, these possible sulfur intrusions support Licensee's failure scenario and control mechanisms.

(2) <u>Dillon's Recommendation of an Additional Test</u>

57. TMIA attempts to support Contention 2.a by noting that the NRC Staff rejected Mr. Dillon's suggestion (SER Att. <u>3</u> at <u>12</u>) that Licensee perform an additional corrosion test in a cold high oxygen and high concentration sulfate environment.

See TMIA 1st Resp., to Interrog. 2.a-1. Mr. Dillon's recommendation, however, was made because of his concern that the cleaning process might cause damage to the OTSGs; Mr. Dillon expressed no concern that the corrosion would otherwise reinitiate.

58. Moreover, Mr. Dillon had suggested this test based on his belief that the TMI-1 steam generators would experience these conditions for a long period of time after cleaning (_see_ complete discussion in SER Att. 3, at 12). After the April 15, 1983 Dillon report was written, however, Licensee conducted instead a corrosion test which simulated the conditions planned and later actually experienced before, during, and after conduct of the chemical cleaning program. Based on performance of this more appropriate test, the Staff rejected Mr. Dillon's comment. _See_ discussion of the corrosion test actually performed at page 29 of the SER.

(3) _Sulfur in the TMI-1 Tubing_

59. The Joint Intervenors have suggested that early studies by H. Coriou and other researchers (described in the article "Historical Review of the Principal Research Concerning the Phenomena of Cracking of Nickel Base Austenitic Alloys") finding cracking of Inconel in pure water may be germane to the present cracking problem. _See_ J.I. 1st Resp., to Interrogs. 1(2)-3, 1(2)-6, 1(2)-7, 1(2)-12. Neither the material nor the environment involved in Coriou's tests is representative of the TMI-1 steam generators on the primary side. The Coriou study

considered mill annealed Inconel, while TMI-1 tubing is sensitized and hence more resistant to pure water cracking. The "pure water" environment of the test is equally incompatible with the boric acid environment in the TMI-1 primary system.

60. Similar tests to Coriou's, conducted by B&W using the appropriate environment and material which exists in the primary system, demonstrated that cracking would not be anticipated. These tests served as a basis for licensing all sensitized Inconel 600 steam generators. Further evidence of the proprietary of the B&W generic tests is the approximately one hundred OTGS operating years of experience at TMI-1 and other plants. When the environment is maintained within the reactor coolant specifications considered, no corrosion occurs.

61. The TMI-1 tubing has been verified to fall within the range of material properties represented by the B&W tests. Evidence specific to the TMI-1 cracking problem is supplied by the short and long term corrosion programs. No cracking has occurred in the absence of a metastable sulfur species contaminant in the coolant.

(4) The Role of Other Potential Causative Agents

(a) Overview

62. The program for identifying the causative agent(s) proceeded by first searching for and identifying all chemical species present on tube surfaces, then examining the possibility that each species contributed to IGSAC. Of the contaminants found in the tube surfaces, only sulfur, carbon and chlorine

were present in sufficient quantities to be involved in the IGSAC process, and each was examined in detail. (Alloy elements were not considered to be causative agents for the reasons discussed in ¶¶ 59-61). Surveys of available literature, and the tests and analyses relating to the three parameters of IGSAC, established that sulfur was the most likely cause of the IGSAC.

(b) Whether Other Agents Could Have Been the Primary Cause of the IGSAC

63. Carbon in the form found on the TMI-1 OTSG tubes has been found during several failure analyses of Inconel 600 steam generator tubes in other plants, but has been determined not to be the cause of the IGSAC. Like the carbon found on the TMI-1 tube surfaces, the carbon in those cases was detected in the long chain or graphitic form in high percentages at the outer surface of the tube film. There is no evidence that the graphitic form of carbon causes IGSAC.

64. Sodium carbonate can cause IGSAC. However, this attack occurs under high pH, high temperature conditions, and causes a caustic type of IGSAC. Sensitized Inconel 600 is very resistant to caustic IGSAC. Moreover, no carbonates were detected on the TMI-1 tube samples.

65. Joint Intervenors have sought to support Contention 1(5) on the basis of the statement of the Third Party Review Group in its February 16, 1983 report (at 9) that "[c]arbonates in the presence of oxidants at high temperature can produce IGA

and IGSCC of Inconel 600." The work to which the TPR is referring is research performed by Westinghouse Electric Corporation under an EPRI funded program. The final report on this project was released in May 1983 and is entitled "Effect of Calcium Hydroxide and Carbonates on IGA and IGSCC of Alloy 600" RP-3060. A review of this document revealed a number of significant factors:

(a) The tests were conducted exclusively using secondary side water chemistry environments. The all-volatile high pH chemistry of the secondary side is significantly different from the borated water, buffered system of the primary side;

(b) The tests were performed to study the influence of carbonates on crevice corrosion of Inconel 600 at tube support plate and tubesheet crevices. No such crevices exist on the primary side; and

(c) The test tubes used in the program were in the mill annealed condition and were not sensitized as in the B&W OTSGs. In view of the fact that the sodium carbonate corrosion is an alkaline corrosion mechanism probably similar to caustic cracking, the sensitized microstructure would be more resistant to this attack.

From this review it is clear that the TPR's concerns for carbonate do not apply to the primary system environment and the corrosion which was observed on the OTSG tubing. Further, the TPR in Supplement 1 (at 3) indicates their concerns are satisfied if Licensee uses a total organic carbon (TOC) analyzer and applies a 1 ppm TOC administrative limit. Licensee has purchased a TOC analyzer and implemented a program to maintain TOC below 1 ppm.

66. Chloride, like carbon, could not by itself have caused the IGSAC. Chloride levels in the coolant were within

specification levels. Some chloride was found on the tube surface, but its level rapidly diminished deeper into the film. Moreover, Inconel 600 is considered virtually immune to chloride-induced stress corrosion cracking. Chloride in levels as high as 10 ppm did not cause cracking in the short term tests discussed above.

67. <u>Other elements</u> (<u>e.g.</u>, antimony, cobalt, zirconium, silicon, phosphorous and titanium) were found only in trace amounts in isolated locations; lead and mercury, other potential corrodants mentioned by the TPR (February 16 report at 9) were not detected. No trends were established. These are normal trace elements expected to be found on surface films as a result of oxidation of various coolant materials putting metal ions into solution. Accordingly, they could not have been the cause of the IGSAC of the TMI-1 tubing.

(c) <u>Possible Synergistic Reactions</u>

68. Joint Intervenors contend that contaminants described in paragraphs 63 - 67 above, or unidentified agents for which Licensee failed to search, might have a synergistic effect even if they could not themselves have caused the corrosion. It has been clearly established that sulfur forms were the cause of the tube damage, and that without the conditions necessary to recreate the sulfur-induced cracking mechanism, the tube damage will not reoccur. This does not mean, however, that synergistic reactions could not have contributed to the sulfur-induced damage mechanism that took place. Licensee took the

possibility of synergistic effects into account in seeking to identify the source of the tube damage, in its short and long range testing programs, and in its operational chemical control programs.

69. Licensee searched for all possible causative or contributory agents. Of the agents found on the tube surfaces, only chloride appeared likely to have a synergistic effect. This was taken into account. The test solutions in the long-term test contained maximum levels both of sulfur species and chlorides allowed by current TMI-1 chemical specifications. The short term tests used 10 times the allowable levels of thiosulfate and chlorides. Both tests used actual TMI-1 tubing, and hence would have had any other contaminant to which the tubes were exposed represented in the tests. No IGSAC has developed.

70. Both the testing programs and administrative controls instituted at TMI-1 consider all chemical species as well as sulfur. In both the short and long-term corrosion tests, samples of actual TMI-1 OTSG tubing were used. This tubing was subjected to the explosive repair and the hydrogen peroxide sulfur removal processes, and thus is representative of the expected tube surface distribution of contaminants.

71. In the actual plant systems, sulfur and chlorides are being controlled to low levels which will not cause IGSAC. The analysis frequency for these species is specified to be frequent enough that an out of specification condition will be

recognized and corrected before tube damage can occur. In addition, the requirement that conductivity be monitored will identify the introduction of any chemical species for which there is no routine analysis. Organic carbon which could be introduced by oil or solvent contamination, will be detected by the newly purchased Total Organic Carbon Analyzer. Administrative controls on the levels of contaminants in chemicals to be added to the system also cover other contaminants than sulfur.

72. In summary, although sulfur was the direct cause of the IGSAC, both the corrosion testing programs and administrative limits on primary system chemistry control all potential contaminants which could cause or contribute to IGSAC.

73. Joint Intervenors cited the work of Dr. R. H. Hansen, retired from Bell Laboratories in Murray Hill, New Jersey as support for their concern as to synergistic conditions. We have undertaken an effort to locate and review all published work by Dr. Hansen. On the basis of that review, it appears that Dr. Hansen's work is wholly unrelated to nuclear energy, steam generators, or the corrodants in issue here.

(c) Control of Contaminants During Repair

74. Careful consideration has been taken to assure that the residue remaining after the kinetic expansion repair process will not contribute to reinitiation of the IGSAC. All consumable materials used during the OTSG repair were analyzed to prevent introduction of harmful levels of contaminants to the reactor coolant system. Sulfur, halogens (chloride and

fluoride), and the heavy metals (arsenic, antimony, bismuth, cadmium, lead, and mercury) were controlled. After repairs were complete, large pieces of material were physically removed. The OTSG tubes and tubesheets were then flushed until soluble contaminants had been essentially removed.

75. As noted above, the tube samples exposed in the short and long term corrosion tests were cleaned in the same manner as the actual tubes, with the exception that they were only rinsed. Thus, the levels of any harmful species in the explosive residue on these tubes would be higher than in the actual OTSG. No corrosion occurred in the tests under conditions comparable to those which will be present during actual operation.

(d) Minor Differences in the Two Independent Failure Analyses

76. TMIA appears to be concerned that the "minor differences" in findings between the two independent failure analyses (referred to in the Third Party Review ("TPR") February 18, 1983 report, finding C.1), somehow undermine these tests and analysis. See TMIA Interrogatory T-22. This is not so. Some differences in outcome are to be expected, given that the two consultants used different equipment and techniques, and were testing different tube samples. The TPR received an explanation of how these differences were resolved, and was satisfied with the response. The two independent failure analyses were in agreement in all relevant respects, and the TPR determined that the differences were not significant.

II. CONTENTION 2.b.1.

77. TMIA's Contention 2.b.1 concerns the possibility that the peroxide cleaning process undertaken by Licensee posed a substantial risk of corrosion reinitiation; TMIA supports its contention by relying on R. L. Dillon's statement that cleaning might put a large inventory of sulfur into solution. There follows a discussion of this contention.

A. INTRODUCTION

78. The decision to remove residual sulfides from the tube surfaces by a hydrogen peroxide cleaning process was preceded by careful consideration of any risks the process might pose for recurrence of the tube damage induced by sulfur or damage due to the cleaning process itself. Numerous tests were performed to ensure the process would not be corrosive. The concerns expressed by Staff consultant R. L. Dillon, as cited by TMIA in its Contention 2.b.1, were expressed prior to the cleaning. The cleaning has successfully been completed, with no adverse effects on the RCS, and Mr. Dillon's pre-cleaning concerns are now academic.

B. DESCRIPTION OF THE CLEANING PROCESS

79. The process used low levels of hydrogen peroxide to rapidly convert the insoluble reduced sulfur (sulfide) left on the tube surfaces to an oxidized soluble form (sulfate) under protective, high pH conditions. The cleaning process took

approximately 400 hours. The sulfate concentration never exceeded 0.4 ppm, and no damage was detected in the system. Laboratory long term corrosion testing on actual TMI-1 tubing had previously confirmed the safety of the process, and hot functional testing of the OTSGs provided subsequent confirmation of its noncorrosive effect.

C. ANALYSIS AND TESTING OF THE EFFICACY OF THE PROCESS

80. The peroxide chemical cleaning process employed was based upon development work which was performed at Battelle Columbus Laboratories. Development began with literature surveys, proceeded through a series of tests employing pure nickel sulfide to explore reaction kinetics, and culminated with tests on actual TMI-1 OTSG tubing. Testing was also conducted to characterize the sulfur-containing layers and any surface films which might impact the cleaning process. In all, 38 beaker tests with pure nickel sulfide, and more than 20 tests containing actual TMI-1 tubing specimens were performed by Battelle. The initial tests found that 50-80% of the sulfur would be removed. Later tests performed after refinement of the cleaning conditions showed sulfur removal from the tube deposits of greater than 80%.

D. ANALYSIS AND TESTING OF THE SAFETY OF THE CLEANING PROCESS

81. In developing a cleaning process, two safety concerns were foremost in our minds: (1) the process must be noncorrosive to plant materials, and (2) the process must

quickly convert the sulfide on the tube surfaces to the equally innocuous sulfate form under conditions which protect the RCS from further attack.

(1) <u>Effects of the Cleaning Process Itself</u>

82. No adverse effects were anticipated from the pH range to be employed during cleaning (8.0-8.5), which is within TMI-1's technical specifications. Ammonium hydroxide was selected as the reagent for use in raising the pH to avoid the possibility of hideout and future corrosion that a solid alkali might introduce. Based on our own experience at TMI-1 and that of the rest of the industry, where ammonia had been used in the secondary system with similar equipment and at comparable concentrations, we concluded no corrosion would result. Following clean-up, the ammonia ions were to be removed from the system by cation exchange resins.

83. The effects of hydrogen peroxide at the levels to be used (15-25 ppm), and industry experience with this agent, were also analyzed. Hydrogen peroxide is normally created in the area of the core during shutdown at levels of 5-10 ppm. At some PWRs, up to 15-20 ppm peroxide has been added to solubize crud once the RCS has cooled to 130°F. No adverse effects have been observed. The TMI-1 cleaning was to be done at the same temperature and approximately the same concentration.

84. Several other aspects of the cleaning process were considered. A materials review was performed to evaluate the effects of concentrated hydrogen peroxide on the storage and

mixing equipment during the mixing process. That review concluded that these components would not be damaged. Nor would by-products of the hydrogen peroxide cleaning process harm the system. Oxygen created during the decomposition of the hydrogen peroxide would be removed by degassing; other by-products would be removed through ion exchange.

85. Finally, the potential effects of impurity introduction associated with the cleaning process (e.g., the potential for chloride throw from the resin during removal of the sulfate) were evaluated. The analysis established there would be no adverse impact on the rest of the plant.

(2) Effects of the Cleaning on the Sulfur on the Tube Surfaces

86. During the cleaning process, parameters such as pH and maximum sulfur concentration were selected to assure that the conditions under which Inconel 600 tubing is attacked by sulfur would not occur. Laboratory testing had demonstrated that metastable forms of sulfur such as thiosulfate can induce cracking at low concentrations but that higher levels of sulfate cannot. While sulfur in metal sulfides is being oxidized to form sulfates, it can be expected to pass through the metastable states. The more rapidly the conversion to sulfate takes place, the lower the concentration of metastable species which exist at any given time. A high pH was used to maximize reaction rate and minimize corrosion possibilities.

(a) Short Term Corrosion Tests

87. An extensive testing program was performed at Battelle to confirm that the conditions of the cleaning process would not reactivate the cracking mechanism. The first series of tests was designed, among other things, to verify that the conditions selected would not result in high levels of intermediate, and potentially harmful, sulfur species. The tests involved consisted of stirred beakers, maintained at constant solution temperatures, in which synthetic reactor coolant solution spiked with measured quantities of pure powdered nickel sulfide were treated with hydrogen peroxide. Sulfate levels and hydrogen peroxide levels were monitored in the stirred solutions. The effects of varying pH values and different pH control agents were also explored, and the rate of sulfate production from one intermediate sulfur species, sodium thiosulfate, was measured.

88. This test series demonstrated that the conversion from nickel sulfide to soluble sulfates occurs at a very rapid rate. Indeed, the levels of intermediate sulfur species produced during the sulfide to sulfate conversion was below the level of detectability. Additional confidence in this conclusion was provided by the rapid conversion of thiosulfate to sulfate under the same alkaline conditions.

89. A corrosion test series was then performed exposing U-bend specimens of sensitized 304 stainless steel and Inconel 600, as well as internally stressed C-rings fabricated from

TMI-1 tubing specimens, to the cleaning solution. Sulfur, in the form of sodium sulfide, was introduced over the first half of the test, and an oxygen cover gas was employed to simulate the higher oxygen levels expected under the actual conditions expected if used in the plant. No cracking or corrosion attributable to the peroxide cleaning process was observed in any of the specimens after 14 days (336 hours) exposure to the cleaning solution and additional sulfide.

90. Chemical analyses performed during these tests failed to identify potentially harmful intermediate sulfur species in the test solutions. This evidence, combined with the rapid formation of sulfates when soluble intermediate sulfur species were introduced to cleaning solutions, demonstrated that the levels of the intermediate species produced are extremely low. After completion of the test, an extensive examination by SEM/EDAX, ESCA and optical microscopy was performed on specimens used in developing the peroxide cleaning process. In no instance was any evidence observed of corrosion attributable to exposure to the peroxide cleaning process.

(b) Long Term Corrosion Tests

91. Pilot loop testing of the process was performed concurrently with the last series of beaker testing. The loop very closely duplicated the conditions of the actual cleaning for a period of 500 hours. It included corrosion specimens of representative primary system materials including sensitized 304 stainless steel, as well as actual tubing sections (one

with an identified defect) from the TMI-1 OTSGs. No evidence of corrosion or reinitiation of cracking was found in this test.

92. All of the tube specimens from the pilot loop test of the peroxide cleaning process were included in long term tests in which the specimens are being exposed to simulated reactor coolant containing the maximum amount of contaminant permitted under current specifications. The tests have undergone simulated hot functional testing followed by simulated operating cycles. No evidence of corrosion has been detected.

E. THE ACTUAL CLEANING PROCESS

(1) <u>The Conditions Maintained During Cleaning</u>

93. Based upon all of the testing performed, the following parameters for the actual cleaning process were established:

pH	8.0 - 8.5
Boron, ppm	1800 - 2300
Chloride, ppm	0.4 maximum
Fluoride, ppm	0.1 maximum
Lithium, ppm	1.8 - 2.2
Hydrogen peroxide, ppm	15 - 25
Total gas, cc/Kg	190 maximum
Temperature, °F	130
Pressure, psi	307

94. Prior to the introduction of hydrogen peroxide during the actual cleaning process, all other conditions described in the preceding table were established and the plant was stabilized. Hydrogen peroxide was then introduced and maintained for a period of 400 hours. Monitoring of plant conditions

occurred continually. Following the 400 hour period, the hydrogen peroxide was allowed to decay and anion rich mixed bed ion exchangers were employed to reduce the sulfate level to less than 100 ppb (which had been demonstrated by testing to be noncorrosive). Finally, cation rich mixed bed ion exchangers were employed to reduce the levels of ammonia to less than 10 ppm.

(2) The Results of the Cleaning

95. During the entire cleaning process, a total of 0.22 lb of sulfate was generated and removed. Actual sulfate levels generated during the cleaning process were lower than anticipated, with a maximum of about 0.4 ppm observed. This is not corrosive at the elevated pH in use. Corrosion tests had found no corrosion when actual TMI-1 tubing underwent simulated cleaning in a solution spiked with concentrations of 20 ppm sulfate. Based on these tests Licensee had conservatively established a 2-5 ppm upper limit on the concentration of sulfur (measured as sulfate) which would be permitted in the RCS during cleaning.

(3) Corroboration by the Hot Functional Testing

96. Primary to secondary leakage was carefully monitored during the period of hot functional testing which followed the cleaning. Measured leakage has remained very low throughout the test period. This serves to confirm the results of the corrosion testing and demonstrates that the cleaning process did not reinitiate the original cracking process.

F. CAUTIONARY STATEMENTS BY CONSULTANTS

97. Before the cleaning actually took place, R. L. Dillon had expressed some reservations as to the cleaning process. However, this was because he estimated that 5-10 ppm of sulfur compounds would be put into solution. As noted, only 0.4 ppm sulfate was generated. Moreover, even with his inflated estimate, Dillon concluded that "restart is appropriate" based on his "consideration of corrosion related factors." SER Attachment 3 at 14.

98. Also before the cleaning, the Third Party Review Group (TPR) had noted, in the context of arguing there was no need to perform the cleaning process, that "there is much about the reactions between peroxides and system materials which is not well understood. So that (in spite of testing) there remains a risk that the process could be detrimental." TPR May 18, 1983 Supplement at 6. But even before the cleaning, the TPR viewed the risk as inconsequential; the TPR concluded that while peroxide cleaning was not essential to plant safety, "nor is peroxide flushing expected to have an adverse impact on plant safety." Ibid. The success of the cleaning effectively moots their concern in any case.

III. TMIA'S CONTENTION 2.b.2 AND JOINT INTERVENORS' CONTENTION 1(2)

99. TMIA's Contention 2.b.2 asserts that the sulfur contamination which is left after cleaning could cause reinitiation of the IGSAC. Joint Intervenors' Contention 1(2) similarly asserts that active forms of sulfur can be generated from the sulfur remaining on the tubes after cleaning. There follows my response to these contentions.

A. INTRODUCTION

100. Sulfur has a number of oxidation states ranging from sulfate, which is present in the reactor coolant, to sulfide, which is present in film on the tube surfaces. Neither of these two forms of sulfur is harmful to the tubes. However, intermediate species between the two extremes are aggressive, and if present in sufficient quantities, could cause reinitiation of the cracking mechanism.

101. The purpose of the peroxide cleaning process was to convert sulfides on the metal surfaces to soluble sulfate so that active, harmful forms of sulfur will not be generated in a concentration to cause IGSAC. Chemical cleaning removed the more readily accessible sulfides; any sulfur remaining is expected to go more slowly into solution. Licensee has taken a number of steps to assure these active forms are not formed from the sulfide remaining after cleaning. The primary measure to be taken to prevent reinitiation of IGSAC is to control

reactor coolant system conditions so that the harmful levels of intermediate sulfur species cannot occur. This is done by (1) controlling the total inventory of sulfur and other potential contaminants in the reactor coolant system and (2) by avoiding system conditions favorable to formation of intermediate species. Before turning to a discussion of these controls, a brief discussion of the chemistry principles affecting the stability of various sulfur forms may be useful.

B. SULFUR CHEMISTRY

102. As noted, the sulfur as currently present in the TMI-1 OTSGs, as sulfides on the tube surfaces and as low levels of sulfate in the coolant, is not corrosive. The crucial question, therefore, is whether significant levels of agressive intermediate species are likely to occur.

103. In general, the higher oxidation number species (e.g., sulfate) are stable under oxidizing conditions and the lower oxidation number species (e.g., sulfide) are stable under reasonably reducing (deoxygenated) conditions. Many intermediate species are metastable.

104. Correspondingly, sulfate and sulfide are generally the dominant equilibrium species within the pH and temperature ranges of interest for normal reactor coolant system operation. Sulfate is the equilibrium specie at room temperature in oxygenated water at pH equal 5. Sulfide, on the other hand, is the stable specie under normal operating conditions

(deoxygenated, temperature above 250°F) and pH levels. Metastable intermediate species such as thiosulfate can only persist within a very restricted pH and oxidization range.

105. Under the reducing conditions which exist in the RCS during the hot functional test, the thiosulfate which contaminated the PWR primary system transformed towards more reduced metastable species. However, during cooldown following hot functional test, oxygen was introduced into the system. The oxidizing conditions in the presence of aggressive metastable sulfur species was responsible for cracking.

106. Under normal operating conditions when the primary system is deaerated and hydrogenated, nickel sulfide will remain stable, and aggressive intermediate species will not be formed. Limited quantities of nickel sulfide may, however, be slowly dissolved in the primary coolant and be removed by the ion exchange resins.

107. It is recognized from the thermodynamic stability of sulfide that oxidation of residual nickel sulfide to sulfate can and will occur to some extent when the primary system is cooled and oxygenated. By the same token, however, control of system oxygenation during cooldown will avert this formation.

C. THE CONTROL METHODS

(1) Control of Sulfur Levels in the Reactor Coolant System

108. Control of sulfur levels in the future is to be accomplished first of all by limiting the introduction of sulfur compounds to the reactor coolant system. Accordingly, the sodium thiosulfate tank has been physically disconnected from the reactor coolant system, and sodium thiosulfate is no longer used at TMI-1.

109. Administrative controls on the addition of chemicals to the reactor coolant system have also been strengthened. All chemicals for use in the reactor coolant system are procured to specifications which have been upgraded since the tube failures. Purchase requisitions for chemicals for reactor coolant system use are reviewed by Plant Engineering and Quality Assurance to ensure that the proper specifications, confirmatory analysis, and quality assurance requirements have been included. Upon receipt of the chemicals, Quality Control performs an inspection to ensure that these purchase order requirements have been met. Before it is used in the reactor coolant system, each lot of chemicals is analyzed for allowable contaminants in accordance with the applicable specifications. Chemicals that were not supplied with an official analysis by the vendor are sampled and analyzed by Licensee. Chemical additions are recommended by the Plant Chemistry Department and implemented by Plant Operations in accordance with established

procedures. Addition points for the Reactor Coolant System are locked when additions are not being made.

110. To ensure that the contaminant level in the reactor coolant system remains acceptably low, chemistry limits for that system have been modified. These limits control the concentration of sulfate to 100 parts per billion (ppb), chloride to 100 ppb, and fluoride to 100 ppb. In addition, the lithium concentration range has been administratively established, within the original B&W specified limit, to be present in the highest concentrations allowed (i.e., 1-2 ppm). This change in lithium specification range has been made to raise the pH of the RCS, which has a positive influence on mitigating the sulfur corrosion phenomenon.

111. To assure that the above contaminants are controlled to the levels specified, sulfate, chloride and fluoride are analyzed a minimum of five times per week. Total sulfate is analyzed periodically, and reduced sulfur is to be analyzed whenever the difference between the sulfate and total sulfur level suggests intermediate species may be present. In addition, conductivity is analyzed fives times a week and is verified to be consistent with analyzed levels of chemical species; inconsistencies will indicate the presence of contaminants in the system.

112. To support the analysis program described above, several new pieces of analytical equipment have been added to the TMI-1 chemistry laboratory. The capability to analyze low

levels of sulfate (down to 30 ppb) has been achieved by the addition of an ion chromatograph. Installation of this equipment has been accompanied by training of operators and development of analytical procedures. A total organic carbon analyzer has also been purchased and put in operation. This will allow us to monitor the primary coolant for organic compounds such as oil and solvents, thus precluding undetected introductions of these substances.

113. In order to prevent the build-up of contaminants, removal of sulfur compounds and other ionic species from the bulk reactor coolant will continue to be done by ionic exchange.

114. In addition to improvements discussed above, strict procedures have already been imposed for maintenance activities with respect to chemical impurities. Currently, a second phase program is underway to identify further possible improvements in chemical control.

(2) Control of System Conditions

115. Licensee's control procedures for reactor coolant system conditions are intended to minimize the conversion of nickel sulfide surface films to potentially harmful intermediate species by preventing the combination of temperature and oxidizing conditions necessary for the formation of the intermediate species.

116. As explained above, the reducing environment which exists during hot operation favors the sulfide form. As such, the generation of intermediate species from sulfide is not a

concern during this phase. During system cooldown, Licensee's new controls require that reducing conditions be maintained until the system temperature is close to ambient; the system will then be nitrogen blanketed to exclude oxygen. The routine monitoring of sulfur levels during layup will verify that corrosive levels have not been formed. Irrespective of the percentage of sulfides actually removed by the cleaning process, these chemistry controls will ensure the inactive sulfides remaining will not generate active species in sufficient concentrations to damage the steam generator tubes.

D. TESTING TO CONFIRM THAT CORROSION WILL NOT REINITIATE

(1) Qualification of the Joint

117. The qualification of the explosively expanded joint considered leak tightness, load carrying capability, residual stress, changes in strength, dimensional changes, transition zone size and shape, and stress corrosion resistance. The tests performed, which included residual stress measurements, hardness testing, profilometry measurements, and load carrying capability confirmed that the expanded joint meets licensing standards for mechanical tube-to-tubesheet joints. Corrosion testing provided data that the expanded region was in a condition which was as resistant to IGSAC as any OTSG tube-to-tubesheet joint.

(2) Short Term Tests

118. Some of the tests which were performed to verify the failure scenario also support the conclusion that corrosion will not reinitiate. The initial tests done using actual TMI-1 OTSG tubes under simulated hot functional tests indicated that at less than 1 ppm of thiosulfate, no IGSAC occurred.

119. Additional short term tests used actual TMI-1 OTSG tubes that had been kinetically expanded, rinsed, and exposed to simulated hydrogen peroxide cleaning process. Thus, these tubes would have surfaces representative of those in the actual OTSGs with respect to levels of contaminants and their forms. Effect of system chemistry was tested by exposing these specimens to simulated reactor coolant containing 1 ppm of both thiosulfate and chloride. No IGSAC was on the tube ID detected during these short term tests.

(3) Long Term Tests

120. To assure that Licensee's controls on sulfur levels and system conditions will prevent the sulfide containing oxide films on tube surfaces from causing initiation or propagation of IGSAC, Licensee has established and is conducting a series of tests on actual OTSG tube samples to study long term effects. The long term corrosion test program is scheduled to run approximately 17 months and will lead the actual operation of the steam generators by at least 1 year. The objective of the tests is to verify that the metallurgical, environmental, geometric and surface conditions which existed after kinetic

expansion in the steam generators and after the peroxide cleaning are not detrimental to tube integrity.

121. In all, four corrosion loops are being run. These test loops are dynamic loops capable of independent flow, pressure and temperature control. Three of the test loops contain actual TMI OTSG tube samples that have eddy current defects indicative of IGSAC. Two of these samples are placed on test in the as-removed condition. The third sample is being tested in a separate loop after having been subjected to the peroxide cleaning cycle similar to that being used in the reactor coolant system. Two loops contain actual tube samples without any eddy current indications. One test loop contains two kinetically expanded samples without eddy current indications that have been subjected to the peroxide cleaning. C-ring specimens stressed near yield are being exposed to all environments.

122. These tests simulate environmental and operational conditions which are representative of the worst case chemistry conditions which could exist in the primary system within technical specification limits. Boron concentrations have been selected to represent the varying levels which will exist in the reactor during one fuel cycle. Lithium levels have been chosen within the established administrative limits for operation and will vary with boron concentration. Contaminant levels in the test loops have been set as chloride nominally 10 ppm, fluoride nominally 0.1 ppm, with one loop having thiosulfate nominally

0.1 ppm, and the three other loops having sulfate at nominally 0.1 ppm.

123. The test loops are undergoing simulated hot functional test cycles followed by simulated operating cycles. These tests duplicate actual operations in terms of temperature, pressure, operating stress on the tubes, and typical duration of heatup, operation, and cooldown. To date, the thiosulfate test and one sulfate test have undergone hot functional tests and four operating cycle simulations consisting of a total of approximately 330 days of operation. The two tests which were exposed to the hydrogen peroxide cleaning have received 500 hours of peroxide cleaning, one hot functional test, and two operating cycles, for a total high temperature exposure in the order of 200 days.

124. To date, specimens subjected to the peroxide cleaning process have experienced approximately 200 days of testing; those not cleaned have been tested for approximately 330 days. No propagation of eddy current indications has occurred. Also, visual metallographic examination and ECT of C-ring specimens removed from all four test loops have shown no IGSAC and no evidence of propagation of IGA.

(4) Hot Functional Testing

125. The hot functional test performed in August and September 1983 provided further assurance that Licensee's control program for preventing reinitiation of IGSAC is effective. During this test, the reactor coolant system was maintained at

hot standby temperature and pressure. Steady state leak rate remained very low throughout the test program. There has continued to be no evidence of initiation or propagation of IGSAC after this test.

E. SPECIFIC POINTS RAISED BY INTERVENORS

(1) Cleaning of Small Bore Piping

126. Piping less than 1 inch in diameter was not flushed as part of the hydrogen peroxide cleaning process. The amount of sulfur in these lines is expected to be negligible compared to the total sulfur inventory. The surface area of these lines is small relative to the balance of the reactor coolant system, representing less than 5% of the surface area of the RCS. Even in the unlikely event an additional 10% of the total sulfur removed by chemical cleaning process were present on the 1 inch or less diameter pipes, and went immediately into solution, sulfur measured as sulfate would be less than half the administrative limit. As reported in TR-008 at 33, flushing the other 95% of the RCS with hydrogen peroxide for one month resulted in a maximum sulfur as sulfate concentration of only 400 ppb. Therefore, the amount of sulfur compounds that could be transported to the steam generators is insignificant and well within the capacity of the reactor coolant clean up system to control. In TMIA's discussion of this residual sulfur, intervenors use the phrase "particularly at the crack tip" to discuss conditions of crack growth. This phrase is without meaning since crack growth (by definition) occurs only at the crack tip.

(2) Effect of 0.1 ppm Sulfate

127. Sulfate is a potential corrodant only at high concentrations; the levels specified for normal reactor chemistry are not aggressive to Inconel 600 tubing. This was demonstrated in the short term corrosion tests, where actual TMI-1 tube samples were exposed to sulfate concentrations up to 10 ppm at low temperatures. No IGSAC was detected. Similarly, the long term corrosion tests are exposing actual TMI-1 tube samples to simulated reactor coolant containing 0.1 ppm of sulfate over long periods of time. No propagation of IGSAC or IGA has occurred.

128. Moreover, Licensee is unaware of and unable to locate any published research on dilute sulfate (less than 1 ppm) causing stress corrosion of Inconel 600 at operating conditions. Sulfate corrosion has only been observed in high temperature, high concentration acid sulfate solution under highly stressed conditions as discussed in EPRI Report NP-3043 "Stress Corrosion Cracking of Alloy 600 and 690 in Acidic Sulfate Solutions at Elevated Temperatures." Other specific issues identified by the Joint Intervenors as supporting this contention are discussed in response to Contentions 2.a and 1(5).

(3) Oxidation of Nickel Sulfide

129. As has been demonstrated in the long term corrosion tests, oxidation of nickel sulfide from OTSG tube surfaces under normal reactor operating conditions is not detrimental; in the long term, this oxidation will serve to remove that portion of the sulfur still remaining on the OTSG tube surfaces

after peroxide cleaning. Moreover, Licensee's controls on sulfur in the reactor coolant system will ensure that oxidation of nickel sulfide will not lead to harmful concentrations of intermediate sulfur species.

130. Dr. Digby MacDonald had initially suggested chemical cleaning to mitigate the possibility of oxidation of nickel sulfide causing corrosion. At the March 10, 1983 meeting of the NRC, Dr. MacDonald indicated he was satisfied, on the basis of the cleaning, the tests performed by Licensee and the controls it has initiated, that no harmful oxidation of the nickel sulfide will occur.

IV. JOINT INTERVENORS' CONTENTION 1(3)

131. Joint Intervenors assert that "morphological changes" in the inner tube surface, remote from the expanded joints, might be "precursors of IGSCC" (which I have been referring to in this affidavit as IGSAC). There follows a discussion of this contention.

A. INTRODUCTION

132. The only morphological changes other than IGSAC that have been identified in the TMI-1 OTSG tubes consist of intergranular attack (IGA). IGA is a corrosion phenomena which, like IGSAC, requires an aggressive environment as well as a susceptible material. Unlike IGSAC, however, IGA formation does not require an applied stress. IGA is directionally non-specific, that is, it follows the material grain boundaries in a random fashion. It is primarily found as a network of attack associated with a main intergranular crack. IGA can also exist as a separate form of corrosion, much like pitting attack, which progresses as long as the correct local corrosive conditions are present. Conversely, IGSAC can be found in the absence of IGA.

133. It is possible that IGA could propagate into IGSAC _if_ the appropriate corrodant were present and a tensile stress were applied. Even under applied stress, however, IGA cannot continue to propagate or become IGSAC in the absence of a corrodant. Because sulfur and other contaminants are not now

and will not be present in the future in corrosive levels, IGA will not reinitiate or propagate into IGSAC in the TMI-1 OTSGs.

B. MORPHOLOGY OF IGA

134. Intergranular attack manifests itself with three levels of severity, each with a different morphology. First, the majority of the tube-observed IGA consists of only minor surface etching, a maximum of 1-2 grains deep (.001 inch). This surface IGA has been identified in the industry as an etching phenomena typical for Inconel 600 tubes which have received an acid pickle as part of the tube fabrication process. This condition exists in many operating steam generators today and is not indicative of any increased propensity for corrosion. Joint Intervnors appear to agree; they did not identify this form of IGA as a potential precursor of IGSAC.

135. The second type of IGA is called IGA "islands". These are small patches generally 4-5 mils in depth and 3-4 mils wide where a small network of IGA exists. The grains remain in place, although the grain boundaries have been attacked.

136. The third type of IGA is called "pitting". This is simply an IGA island from which some grains have fallen out. This causes a pitted surface on the OTSG tubes.

C. EVALUATION OF THE IGA IN THE TMI-1 OTSGS

137. A total of 29 samples were removed for metallographic examination from 16 TMI-1 OTSG tubes. Of the 29 samples, 20 were from the upper tubesheet (UTS) region. Of these, two showed IGA which was not associated with IGSAC. These two locations were within the top nine inches of a single tube. In eight of the mounts, IGSAC was observed without IGA. In seven, islands of IGA were found in the vicinity of IGSAC cracks. Three of the mounts did not show any damage, either cracking or deep IGA (although minor surface etching was found).

138. Nine samples from the freespan were examined. No IGA islands were found in any of the mounts. Three samples had IGSAC without any IGA, and six samples had no damage whatsoever, only minor surface etching.

139. Although it is quite possible that some IGA islands are present in the freespan ("remote from the expanded joints") in tubes which were not examined, the metallographic examination of the 29 samples demonstrates that the majority of intergranular attack is (1) located in the upper tubesheet region, and (2) associated with cracks. This is as would be expected, because the concentration/aggressiveness of the corrodant was highest in the upper tubesheet region, particularly in the area of the cracks; the magnitude of any intergranular attack is dependent on the strength of the corrodant at a particular location, the susceptibility of the material and other localized conditions. In regions away from

cracks where the corrodant levels were lower, the degree of IGA was less. Often a small island of IGA would be associated with a deposit on the surface which may have provoked the attack in that region.

140. Licensee also visually examined 36-inch sections from below the UTS of two tubes which were free of eddy current indications. These samples were sectioned in half, and then bent to put the entire ID surface in tension. No cracks or IGA islands were detected on the samples under visual examination at magnifications up to 20X.

141. A surface analysis of the oxide film in the region where the bends were made (approximately 290" from the UTS face) was also performed. It did not reveal the presence of any sulfur. This same tube did, however, show sulfur in the surface oxide in the UTS region. On other samples where sulfur was detected in surface film below the UTS region, concentrations were significantly lower (less than 2%) than that observed in the vicinity of cracks found within the UTS region.

142. Finally, Licensee analyzed the effect of the IGA on the mechanical properties of the tubes. This involved first of all performing metallographic examinations of tube samples containing both IGA and IGSAC from TMI-1 steam generators. These examinations showed that base metal microstructure was consistent along the length of the samples and between the different samples analyzed. The microstructure consists of discrete chromium carbides in the grain boundaries, with a

moderate dispersion of carbide within the grains. This microstructure is typical for tubing material used in B&W steam generators, and is representative of their mill annealed plus stress relieved heat treatment.

143. Mechanical testing was then performed on actual TMI-1 OTSG tubes. Two tubes which did not have any eddy current indications were tested. The material's strength and ductility conformed to the original specification requirements. One tube section containing a defect was also tested. Reduction in strength was proportioned to the area occupied by the defect.

144. These tests demonstrate that the material not directly affected by IGA or IGSAC retains its original strength and ductility. Since the cross-sectional area occupied by IGA islands is very small, its presence has an insignificant affect on strength and ductility. It therefore must be concluded that the conditions which resulted in IGA of the TMI-1 OTSG tubes did not adversely affect the tubes' mechanical properties.

D. PREVENTION OF PROPAGATION OF IGA

145. Because the presence of a corrosive agent is necessary for the propagation of IGA, the same strategies which have been instituted to control the presence of contaminants and conditions necessary for IGSAC will also serve to prevent propagation of IGA, and to prevent IGA from propagating as IGSAC. These strategies are described above in paragraphs 102-110 above of my affidavit.

E. CONFIRMATORY TESTING

146. Tests performed on actual OTSG tubing have confirmed that propagation of IGA is not occurring and that the control measures will be effective. Immediately after discovery of damage to the tubes, a section of OTSG tubing containing a defect was loaded while exposed to actual reactor coolant. No propagation of the defect occurred.

147. One of the objectives of the long term corrosion test was to study the influence of prolonged operation on IGA. To do this, tube samples which have oxide films containing sulfur and eddy current indications indicative of IGSAC cracks are being tested. These samples are being tested in the as-received condition as well as after peroxide cleaning. Dynamic test loops were established to operate under conditions simulating normal reactor coolant system conditions. As of this date, metallography on 13 C-ring specimens removed from that test program has continued to show no evidence of IGSAC or further intergranular attack. This is despite the fact that some samples also contain shallow surface IGA. In no cases has this IGA propagated into an intergranular stress assisted crack.

F. CONCLUSION

148. From our observations, IGA cannot be considered a precursor of IGSAC. There have been IGSAC cracks observed without any IGA, as well as IGA without cracks. As stated above, this is to be expected based on the variability of

stress and corrodant concentration along the tube length. Moreover, the mechanical properties of the tubes have not been adversely affected. The short and long term corrosion tests have confirmed that IGA is not a precursor of IGSAC and that Licensee's control strategy for preventing IGSAC will also prevent propagation of IGA.

F. Scott Giacobbe

Subscribed and sworn to me this
[illegible] day of February, 1984.

[illegible]
Notary Public
Bern Township, Berks County, PA

My Commission Expires:

November 8, 1984

Attachment to Affidavit of F. Scott Giacobbe

STATEMENT OF QUALIFICATIONS AND EXPERIENCE

I, F. Scott Giacobbe, am employed by General Public Utilities Nuclear Corporation as Manager, Materials Engineering/Failure Analysis. I have been in this position since July of 1982.

My education includes a Bachelor's Degree in Mechanical Engineering from Villanova University in 1970 and a Master's Degree in Materials Engineering from Drexel University in 1975.

My work experience has provided me many years of direct involvement in the materials evaluation and failure analysis of power plant components; early in my career it also provided a very intense involvement in heat exchanger tubing evaluations.

In 1970, I began my employment with Westinghouse Electric Corporation in their Heat Transfer Division as a Materials Engineer. In this position I worked on the materials selection, corrosion evaluations and failure analysis of heat exchanger components such as feedwater heaters, condensors, radioactive waste evaporators and other secondary side heat exchangers. In particular, I was responsible for assuring that tubing utilized in the Westinghouse heat exchangers was properly specified and manufactured. This function provided me with in-depth knowledge of heat exchanger tubing fabrication practices, corrosion resistant properties and failure mechanisms.

In 1977 I left Westinghouse to join General Public Utilities as a Senior Engineer in their metallurgical laboratory. This position afforded me the opportunity to expand my areas of expertise to include materials selection, corrosion evaluation and failure analysis of other components of both nuclear and fossil power plants, and to gain a broader understanding of power plant operation.

In 1978 I was promoted to supervisor of the metallurgical laboratory. This was a first line supervising position which gave me the responsibility for the daily operation of the laboratory and supervision of the technicians and engineers reporting to me. This position also carried with it a large technical responsibility which kept me heavily involved in the day-to-day materials engineering problems.

My career took on a slight change in direction in 1980 when the company reorganized and formed the Nuclear Corporation. At that time I became Materials and Welding Manager in the Nuclear Assurance Division. With this position I essentially had the same functions as before, with the added responsibility for welding at the nuclear power stations. While in this position I was responsible for the technical and metallurgical aspects of the development of the Nuclear Corporation welding program. During this time I was still supervising all failure analysis activities, including the TMI spent fuel pool pipe cracking incident.

In July 1982, another reorganization took place. At this time my section merged with the materials engineering section in the Technical Functions Division and I took over management of that newly formed section. In this position I now had functional responsibility for the materials configuration control of both GPU nuclear power plants as well as welding engineering and failure analysis. In addition, my section still provided failure analysis services to the fossil companies.

I have been involved in the steam generator tube failure issue from the beginning. I participated directly in the initial decision-making regarding the tube sampling and removal operations and was present to perform the initial visual evaluations of the removed tubing. I personally planned and oversaw the failure analysis activities performed by the outside laboratories. I also developed the corrosion testing programs which GPUN implemented to gain insight and understanding into the failure mechanism and responsible corrodants. It was also my responsibility to coordinate the input from all our technical consultants as well as plant experience and formulate the current failure scenario.

During the steam generator repair, my section also provided materials evaluation and consultation on all aspects of the repair including explosive expansion, flushing, peroxide cleaning, and so forth. My section also developed and implemented the long term corrosion testing program and is evaluating the results as the testing progresses.

Lastly, during the course of the steam generator repairs, I was responsible for making all presentations to the NRC on corrosion testing and failure analysis activities.

Over the years I have kept fully abreast with the state-of-the-art in corrosion technology through my attendance and participation in technical seminars and conferences, and through attending training sessions. I am a member of the Edison Electric Institute Materials, Piping, Welding and Corrosion Task Force, a group of industry representatives who meet to share and develop solutions to corrosion problems in the field of materials and welding in the power industry. In addition, I am a member of the American Society for Metals.

<u>Publications</u>

1. F. S. Giacobbe, "Examination, Evaluation and Repair of Stress Corrosion Cracking in a PWR Borated Water Piping System", NACE Corrosion 81.

2. F. S. Giacobbe, J.D. Jones, R. L. Long, D. G. Slear, "Repairs of TMI-1 OTSG Tube Failures" Plant/Operations Progress AICHE, July 1983, Vol. 2, No. 3.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	ASLBP 83-491-04-OLA
(Three Mile Island Nuclear	)	(Steam Generator Repair)
Station, Unit No. 1)	)	

CERTIFICATE OF SERVICE

This is to certify that copies of "Licensee's Motion For Summary Disposition Of Each Of TMIA's and Joint Intervenors' Contentions" and "Affidavits of David G. Slear, Branch D. Elam, Mary Jane Graham, Stephen D. Leshnoff, and F. Scott Giacobbe In Support of Licensee's Motion for Summary Disposition Of Each Of TMIA's and Joint Intervenors' Contentions" are being served to all those on the attached Service List by deposit in the United States mail, first class, postage prepaid, this 24th day of February, 1984.

Bruce W. Churchill

Dated: February 24, 1984

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	ASLBP 83-491-04-OLA
(Three Mile Island Nuclear	)	(Steam Generator Repair)
Station, Unit No. 1)	)	

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