SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGUALTION

OPERABILITY OF REACTOR COOLANT PUMPS

GPU NUCLEAR CORPORATION, ET. AL.

THREE MILE ISLAND NUCLEAR STATION, UNIT 1

DOCKET NO. 50-289

1. Introduction

On January 27, 1984, with TMI-1 in cold shutdown and reactor coolant pump 1B (RCP-1B) in operation, pump shaft vibration increased from the normal range of 9 to 12 mils to 12 to 15 mils. On January 30, 1984, vibration increased to 19 mils and then to 24 to 28 mils on January 31, at which time the pump was shut down. Ultrasonic inspection of the pump shaft indicated an area of discontinuity in the shaft near the impeller, which coupled with analysis of vibration data and available failure history of similar RCP's suggested a crack in the shaft. After dismantling and examination of the pump, it was determined that the shaft was cracked more than half way through in the vicinity of a 3/8" drilled hole. It was further determined that the impeller vanes were eroded significantly.

The entire rotating assembly in RCP-1B, including shaft and impeller, was replaced with a new assembly, the radial bearing was also replaced, and the pump assembled and balanced.

The other 3 RCPs were examined ultrasonically and no indications of cracks were found (although it is possible that some small cracks nevertheless are present). Enhanced video and still photographs of the bottom of the impellers showed no evidence of damage on the visible side, although erosion on the other side is possible. All pumps were balanced and no indication of unusual vibration was noted. All pumps will continue to be monitored for vibration, including periodic analysis of vibration components felt to be indicative of shaft cracks.

Licensee's submittals to the staff on this matter include:

1. Letter to NRC dated April 10, 1984.
2. Letter to NRC dated October 12, 1984, with attachments.
3. Letter to NRC dated November 2, 1984.

The purpose of this SE is to verify if the damage to RCP-1B has any safety significance and to confirm operability of all RCPs, with emphasis on the following areas:

1. Is pump shaft failure bounded by the FSAR locked rotor evaluation? Is reactor coolant pressure boundary integrity threatened by pump shaft failure?

2. Was the cracked shaft related to the previous sulfur corrosion problem?

3. Is potential impeller degradation on RCP-1A, C, and D safety significant?

2.0 Evaluation

2.1 Is pump shaft failure bounded by the locked rotor evaluation? Is RCPB threatened by pump shaft failure?

The TMI-1 FSAR contains a locked reactor coolant pump accident analysis but does not contain a sheared shaft analysis. In a letter of November 2, 1984, GPU stated that in the event of a sheared pump shaft the rotor would fall into the pump casing and jam so that it could not spin. With the rotor jammed in the pump casing either a locked rotor or a sheared shaft event would produce the same result.

If a sheared rotor were not assumed to drop but to spin freely, the question of whether the locked rotor of sheared shaft case would be bounding would depend on which case would produce the lower flow when the reactor tripped.

Locked rotor/sheared shaft accidents would be terminated by the power-to-flow mismatch reactor trip at TMI-1. Minimum DNBR would occur when the core flow was lowest just before the reactor tripped. Once the reactor tripped neither DNBR or high reactor system pressure would be of concern.

If the rotor were free to spin, the flow resistance through the affected pump and the overall primary system flow resistance would be less than if the rotor were locked. The core flow coastdown would therefore be slower and more prolonged for the free spinning case than for the locked rotor case. After the initial flow coastdown the locked rotor case might produce higher core flows than the sheared shaft case because of reduced flow reversal in the affected loop. This effect has been calculated to occur for Westinghouse plants. The locked rotor assumption would produce a lower flow and be more conservative than the sheared shaft assumption provided that the reactor trip occurred during the flow coastdown period.

The TMI-1 FSAR does not provide a flow coastdown curve for a locked rotor accident. The licensee referenced the flow coastdown curve in the Midland FSAR. Midland has an identical loop arrangement to TMI-1. When TMI-1 is at full power the reactor will trip when the core flow decreases to 90% of its initial value. The trip delay time is 650 miliseconds. As may be seen from the attached Midland flow vs time curve, the control rods would enter the core during the flow coastdown period when the locked rotor case would have the lower flow and therefore be limiting. Based on the Midland analysis and the TMI-1 trip delay time we conclude that the locked rotor case bounds the free spinning shaft case for TMI-1, and therefore the locked rotor evaluation bounds the pump shaft failure with respect to RCS flow and DNBR.

Another consideration with regard to total shaft failure is the possible effect on the integrity of the reactor coolant pressure boundary (RCPB).

If the impeller were assumed to stop abruptly as in the locked rotor case, B&W (in the Midland FSAR) has predicted a 50 psi pressure pulse, and confirms that this will not affect the primary pressure boundary. The staff agrees with this conclusion, and with its applicability to TMI-1.

The licensee notes that in the unlikely event of shaft separation, the reactor would trip automatically on reduced RCS flow rate, and the increase in pump vibration would result in manual pump trip. Since a break below the pump radial bearing would result in the shaft section above the break remaining in place, this would not result in vibration high enough to cause abnormal leakage of the pump seals. Integrity of the motor and flywheel would also not be compromised.

The licensee has stated that the threshold depth of crack at the location in question for significant vibration displacement on the installed monitoring system is 3.4 inches (the shaft is 8.75 inches in diameters), and that at least 1000 hours of operation at normal conditions are available before the crack would propagate to failure from that depth. The licensee has demonstrated that its operating staff is alert to any significant increase in vibration and that action to shut down an RCP will be taken if such vibration approaches 200% of normal displacement levels. Action at or before this level will provide reasonable assurance that the shaft crack will not propagate to failure before the pump is shut down. In any event, as the shaft separation at the Surry plant has demonstrated, such failure, if it were to occur, is not likely to affect the integrity of the RCPB. However, the licensee should assure that the RCP vibration monitoring equipment is properly calibrated and functional in order to permit detection of any crack in sufficient time prior to failure to permit pump shutdown.

Based on the above, we conclude that there is reasonable assurance that the integrity of the RCPB is not threatened by cracking similar to that observed in RCP-1B.

2.2 Is the cracked shaft related to the previous sulfur corrosion problem?

The TMI-1 RCP is a Westinghouse Model 93A with previous history of cracking. The shaft of a Surry reactor coolant pump completely severed in 1974. This was determined to be fatigue, initiating at a sharp groove. Westinghouse replaced the shafts in all Model 93A pumps with a new design without the sharp groove.

In 1981, high vibration was noted in a reactor coolant pump at Prairie Island Unit 2. Subsequent examination showed that the shaft was cracked across more than half of the cross sectional area. In this case, the redesigned shaft had failed by fatigue starting from a drilled hole used to key a thermal shield in place.

The TMI-1 pump shaft cracked at the same location as the Prairie Island pump. The crack also started at a drilled key hole. The extent of cracking is almost identical.

The B&W report submitted with the licensee's letter of October 12, 1984, describes the overall character of the cracking, and includes many photographs including macro and micro fractography. All fractographs are typical of high cycle fatigue fracture, and are essentially identical to what was reported on the Prairie Island and Surry failures.

Nevertheless, there were some relevant differences. In the TMI-1 case, the fractography indicates that the crack grew very slowly (smooth surface, with very fine stop marks and progression lines) for the first one inch in depth. There appeared to be a major arrest at this location, with some indications of pitting at the crack tip, as if the crack had stopped growing, but had been exposed to some corrosive environment. This first inch of crack surface was darker and more reddish in color than the rest of the fracture. There were 15 beach marks (BMs) noted from the point of crack initiation of the drilled hole to the depth where the character of the fracture changed. This major progression point was referred to as "beach mark 15," and used as a reference for crack growth calculations.

Beyond BM 15, the fracture was coarser in appearance, but still typical of transgranular high cycle fatigue. The surface was brighter, with significantly less corrosion products. These characteristics are indicative of high stress levels, lower temperatures, and fast crack growth rate. Fractography located an additional 10 BMs across the remainder of the fracture, comprising an additional 3.8 inches of crack growth.

This major difference in apparent crack growth rate, and the clear BMs (indicating possible pump starts and stops) was noticed at the time an NRC representative examined the fracture early in the B&W evaluation. He suggested that a correlation might be drawn between the periods of crack growth and periods of known pump operation.

This was followed up by calculations performed by Structural Integrity Associates (SIA) for the licensee. The results of these calculations appeared to match the operational periods since the 1983 pump restart very well. It is therefore postulated that the growth up to BM 15 occurred in the period up to 1979, and the rest of the crack growth occurred during the 1983 layup period. We agree that this is a reasonable explanation of the failure history.

A concerted effort was made to determine whether the sulfur contamination of the reactor coolant contributed to the failure. High concentrations of sulfur were found on the fracture surface, as well as in other local corrosion deposits. This would be expected, but the presence of sulfur does not imply a causative factor. The pitting observed at the location of BM 15 could have been enhanced by sulfur contamination in the reactor coolant, but could also have been caused by the sulfur in the sulfide inclusions in the metal. In any case, the fatigue fracture itself showed no evidence of corrosion enhancement. Further, the quantitative crack growth calculations that correlated very well with the observed BMs from BM 15 to BM 25 were based on crack growth data obtained under non-corrosive environments. Any significant increase in crack growth rate caused by abnormal environment would have resulted in faster growth than was calculated, and good correlations would not have been obtained.

On the basis of the information furnished by the licensee, and information available regarding previous Westinghouse Model 93A pump shaft failures, we have concluded:

1. The failure of the TMI-1 shaft was caused by fatigue initiating from a drilled key hole, and was not related to the sulfur corrosion problem previously observed in the steam generator.

2. Early pump operation initiated the crack, and slowly propagated it for one inch.

3. The relatively long period of cold, single pump operation during 1983 with attendant high cyclic stresses propagated the crack relatively rapidly across the remainder of the cracked cross section.

2.3 Is potential impeller degradation on RCP-1A, C, and D of safety significance?

Impeller damage might result in reduced core flow. The licensee indicates that flow measurements are required when the plant reaches 100% power following restart. The reactor core is protected against DNBR by the power-to-flow trip monitor of the reactor protection system. The power-flow logic reduces the high power trip setpoint proportional to the normalized flow. If the impellers were sufficiently degraded the reactor would trip before reaching 100% power. Reactor coolant pump flow is not relied upon as a safety-related function to mitigate any design basis accident. In the case of the locked rotor accident, lower initial flow would lead to an earlier reactor trip; otherwise the consequences would be unchanged. We conclude that TMI-1 is adequately protected from primary system flow degradation, and therefore that impeller degradation is not significant from a safety standpoint.

3.0 <u>Summary</u>

Based on our review as summarized above, we have concluded that:

1. Pump shaft failure is bounded by the FSAR locked rotor analysis;

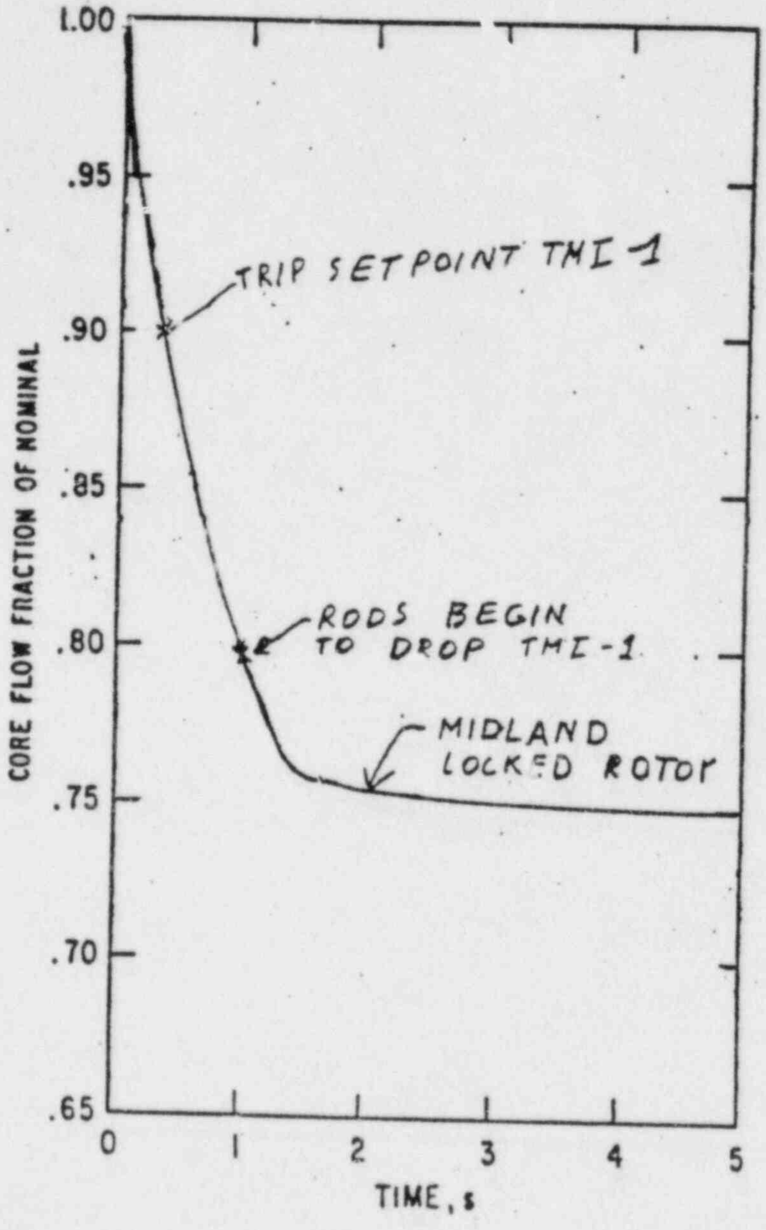
2. There is reasonable assurance that the integrity of the reactor coolant pressure boundary is not threatened by RCP shaft cracking;

3. The failure of the RCP-1B shaft was caused by fatigue and was not related to the sulfur corrosion problem previously observed in the steam generators; and

4. Impeller degradation (erosion) is not significant from a safety standpoint.

Therefore, we conclude that there is reasonable assurance that the health and safety of the public will not be endangered by operation of TMI-1 with the existing reactor coolant pumps.

FIGURE 1



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TIME, s
TRIP SETPOINT TMI-1
RODS BEGIN TO DROP TMI-1
MIDLAND LOCKED ROTOR