U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

Report No. 50-247/80-19

Docket No. 50-247

License No. DPR-26 Priority -- Category C

Licensee: Consolidated Edison Company of New York, Inc.
4 Irving Place
New York, New York 10003

Facility Name: Indian Point Nuclear Generating Station, Unit 2

Investigation at: Buchanan, New York

Investigation conducted: October 22 - November 21, 1980

Investigators:

T. T. Martin, Chief, Reactor Projects Section No. 3, RO&NS Branch	11/28/80 date signed
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J. C. Higgins, Senior Resident Inspector, Shoreham	11/28/80 date signed
T. J. Kenney, Resident Inspector, Indian Point	11/28/80 date signed
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Approved:

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Investigation Summary:
Investigation on October 22 - November 21, 1980 (Report No. 50-247/80-19)
Areas Investigated: Investigation of the circumstances leading to and the results of the Vapor Containment Floor and Reactor Vessel Pit flooding event on October 17, 1980. Areas examined included: Sequence of Events; Licensee Management Activities; Shift Technical Advisor; Reporting; Reactor Trip and Instrumentation Performance; Containment Sump Pumps and Level Instrumentation; Reactor Vessel Pit Sump Pumps; Leak Detection Instrumentation and Procedures; Fan Cooler Units; Reactor Vessel Pit Flooding; Flooding History; Reactor Vessel Integrity Following Immersion; Containment Paint and Insulation; Mirror Insulation; Steam Generator Blowdown Line Leaks and Supports; Corrosion Effects of River Water; Chloride Containment Survey; Non-Destructive Examinations; Quality Assurance and Quality Control Programs; and, System Descriptions. The investigation involved 1300 inspector hours onsite by one Section Chief, six inspectors, and two investigators.
Results: Ten items of noncompliance were identified: (Failure of the Station Nuclear Safety Committee to review potential safety hazards prior to Reactor Startup, Paragraph 4.b; Assignment of an unqualified individual to Shift Technical Advisor duties, Paragraph 5.c; Failure to follow Emergency Procedure for Inoperable Power Range Nuclear Instrument, Paragraph 7.f; Failure to report the Vapor Containment Flooding Event, Paragraph 6.d; Failure to establish adequate procedures, Paragraphs 8.c.(4), 10.b.(4), 10.c.(4), and 22.d; Failure to adequately evaluate the use of Epoxy Material as a Fan Cooler Unit repair material, Paragraph 22.d; Failure to determine, evaluate, and record the causes of leaks, Paragraph 22.d; Failure to promptly respond to QC Inspection Reports, Paragraph 22.c; and, Failure to control and identify material, Paragraph 11.g). One deviation was identified: (Contrary to industry practice, Vapor Containment Sump Pumps were operated without float controller lower guides and with shutoff heads, Paragraph 8.c.(4)).

DETAILS

1. Persons Contacted

The management and supervisory personnel listed below were contacted:

E. Baisel, Instrumentation and Control Supervisor
A. Brescia, Instrumentation and Control Supervisor
J. Cullen, General Supervisor - Health Physics
J. Curry, Chief Operations Engineer
W. Ferreira, Quality Assurance Engineer
R. Flynn, Instrumentation and Control Technician
J. Halpin, Maintenance Engineer
A. Hauspurg, President
J. Higgins, General Chemistry Supervisor
W. Lettmoden, Senior Watch Supervisor
C. Limoges, Reactor Engineer
*J. Makepeace, Technical Engineering Director
*E. McGrath, Vice President of Power Generation
T. McKenna, Maintenance Foreman
*W. Monti, Manager-Nuclear Power Generation
A. Nespoli, Refueling Engineer
R. Orzo, Senior Watch Supervisor
J. O'Toole, Assistant Vice President, Engineering
E. Phillips, Manager, Field Office Quality Assurance
C. Powell, Senior Watch Supervisor
D. Sarc, Acting Maintenance Engineer
T. Schmeiser, Support Facility Supervisor
*M. Shatkouski, Plant Manager
R. Vogle, Health Physics Supervisor
T. Walsh, Instrumentation and Control Engineer
W. Wedler, Qaulity Control Engineer
S. Wisla, Chemistry and Radiation Safety Director
P. Zarakas, Vice President of Engineering

The investigators also interviewed or contacted additional personnel from the operations, health physics, chemistry, test, maintenance, engineering, quality assurance, and adminstrative staffs.

*denotes those individuals present at the exit interview conducted by the NRC Investigation Team on November 18, 1980.

2. Event Summary

Shortly after midnight on Friday, October 17, 1980, operators detected and later verified that one of four Power Range Nuclear Instrument Channels was failing. Following the declaration of the Channel to be inoperable, operators failed to first reduce the Plant power to less than seventy percent before deenergizing the Channel, resulting in an automatic Turbine runback to seventy percent.

During attempts to over-ride the automatic Turbine runback controls, operators turned one of the Turbine load limiters in the wrong direction, causing a further reduction in Turbine power and ultimately a Reactor Trip.

Confident the cause of the runback and trip were known, and being allowed to operate with one Power Range Nuclear Instrument Channel inoperable, the Plant was restarted. With the inoperable Nuclear Instrument Channel in a tripped condition, technicians trouble-shooting the Instrument Channel problem injected a test signal into a second Nuclear Instrument Channel causing it and the Reactor to trip.

Again, confident the trip was understood, the Plant was restarted. Shortly following the return to criticality, licensee management directed the Plant be shutdown to repair the trouble with the inoperable Channel, now known to be within the associated cables or detectors, located within the Vapor Containment.

The first Vapor Containment entry team found several inches of water on the Vapor Containment Floor and river water leaks on a Fan Cooler Unit. The second entry team found hot, humid vapor exiting the Nuclear Instrument Channel detector well, additional Fan Cooler Unit leaks, two Vapor Containment Sump Pumps inoperable and ankle deep water (later proven to be river water) on the Vapor Containment Floor.

A supervisor restarted one of the Vapor Containment Sump Pumps by righting both float operators and restarted the other Pump after replacing its blown fuses. Later, the same supervisor checked for and found water in the Reactor Vessel Pit, several feet below the access grate. Neither he or his supervisors recognized that the water level he reported corresponded to a nine foot level on the outside of the Reactor Vessel.

During the weekend, water was pumped from the Reactor Vessel Pit and Vapor Containment, a leak identified on one Steam Generator Blowdown Line was repaired, and the multiple leaks on each Fan Cooler Unit were repaired.

Early in the morning on Monday, October 20, 1080, with the leaks repaired and the Vapor Containment Floor and Reactor Vessel Pit dry, the Plant was restarted. The Plant was subsequently shutdown when licensee management, returning to work, learned of the flooding of the Reactor Vessel Pit and were concerned with the potential of Chloride Stress Corrosion of the Stainless Steel Incore Instrument Conduits.

Subsequent discussions with the NRC included identification of the concern for the potential that the Reactor Vessel was wetted and the commitment to

NRC that the plant would not be restarted, without first giving NRC four hours warning.

By Monday evening, preliminary licensee calculations of the amount of water pumped from the Vapor Containment and the amount of water necessary to flood to the evelvation of the bottom of the Reactor Vessel, indicated that the Reactor Vessel had not been wetted. The previous observations of the supervisor initially discovering the water in the Reactor Vessel Pit were not compared to Vapor Containment construction elevation drawings at this time. Subsequent water inventory calculations on Monday and Tuesday placed the conclusion, that the Reactor Vessel had not been wetted, in doubt.

On Tuesday afternoon, October 21, 1980, NRC had documented the corrective actions expected of the licensee, had obtained the licensees commitment to complete those actions, and had finalized those actions expected in an Immediate Action Letter, that would be issued the following morning.

The plant was maintained in a hot shutdown condition until Tuesday evening, when the licensee recognized the need to remove the Reactor Vessel Insulation to conduct tests to determine if the Reactor Vessel had been wetted. On Wednesday morning the initial Chloride Swipe Surveys of the Reactor Vessel supported the licensee's belief, but subsequent Swipes with the Plant now in Cold Shutdown again raised concerns that the Reactor Vessel had been wetted.

On Wednesday evening, the NRC Investigation Team arrived on site and began to gather information.

Operators returning from two days off on Thursday, learning of management's investigation, informed their supervisors of their observations of water level in the Reactor Vessel Pit. The reports of these observations, coupled with Friday morning's Reactor Vessel Swipe Survey Analysis results demonstrating the residue was from river water, convinced the licensee that the Reactor Vessel had been at operating temperature while submerged in relatively cool river water to a depth of about nine feet.

During a meeting on Friday, October 24, 1980, the NRC Investigation Team was informed of the licensee's conclusions.

3. Conduct of Investigation

The NRC Investigation of the Vapor Containment Flooding event was initiated on October 22, 1980, and was concluded on November 21, 1980; involved approximately 1300 man-hours; and, was conducted by a team consisting of:

1 - Section Chief
2 - Senior Resident Inspectors
1 - Resident Inspector
1 - Reactor Inspector (Quality Assurance)
1 - Reactor Inspector (Non-Destructive Examination)
1 - Reactor Inspector (Corrosion and Metallurgy)
2 - Investigators

Information was gathered through the conduct of interviews, the taking of sworn statements, the inspection of equipment and tours of affected spaces, the review of procedures, records, logs, and computer printout, the witnessing of tests, independent computation of volumes and flooding elevations, the construction of charts and information flow diagrams, and the independent non-destructive examination of the Reactor Vessel and Incore Instrument Conduits.

The principle products of this investigation are the transcript of the NRC-licensee Technical Meeting in White Plains, New York on November 5, 1980, and this investigation report, including a detailed Sequence of Events attached as Enclosure 1 to the report.

Based on the findings of the NRC Investigation Team and that of the licensee, it was determined that additional information relative to the event and the corrective action required to prevent reoccurrence had to be developed and documented. Enclosure 2 documents those reports the licensee has committed to develop and submit to NRC by December 22, 1980. The licensee is further committed to propose new or additional Technical Specifications for the systems contributing to the flooding event, or modified as a result of the event, by January 15, 1980.

4. Licensee Management Activities

a. Event Narrative

(1) Friday - 10/17/80

Upon discovery of the problem with Nuclear Instrument Channel N42, shortly after midnight, operators notified the first shift Senior Watch Supervisor (S.W.S.) (first line supervision) of the condition, who then called the Chief Operations Engineer (C.O.E.) at home and informed him of the problem. It was decided that the S.W.S. would call the Reactor Engineer and request he come to the plant to conduct a flux map. The C.O.E. called the Plant Manager (P.M.) at home and informed him of the developing problem.

Following the determination by the Reactor Engineer and S.W.S. that Channel N42 was failing and should be declared inoperable, the S.W.S. again called the C.O.E., requesting per licensee procedure that the C.O.E. get permission from the P.M. to operate above 70 percent power with only three Power Range Nuclear Instrument Channels operable. The C.O.E. called and received the required permission, but whether this permission was passed to the S.W.S., prior to pulling the fuses on Channel N42 while at 90 percent power and the resulting Turbine runback, is unclear.

The S.W.S. called the licensee's Operation Control Center (O.C.C.) and informed the watch stander of the runback. Whether the S.W.S. then called the C.O.E., or vice versa, is unclear, but permission to operate above 70 percent was given. The S.W.S. decided to deenergize the Turbine Load Limiters, used by the controls to implement the Turbine runback, and move them out of the way so that power could be raised.

Following the combination operator error-communication failure, that resulted in one load limiter being moved in the wrong direction causing a drop in Turbine Load and Reactor Scram, the S.W.S. again called the O.C.C. and the C.O.E. at home to inform them of the latest events. Based on their confidence that the cause of the trip was known and that no safety problem existed, the S.W.S. recommended and the C.O.E. concurred with plans to restart the plant. The C.O.E. then called the P.M. to inform him of the latest events and to confirm that his decision to restart the plant was appropriate.

The S.W.S. then notified the NRC Duty Officer of the Turbine Runback and Reactor Trip.

The Vice President (V.P.) - Power Generation called the O.C.C. shortly after 6:00 AM, to learn the status of the Power Generation system, and learned of the first Reactor trip and plans for restart at Indian Point Unit 2.

During the conduct of a morning management meeting, which included discussion of the events of the morning, the Reactor was tripped a second time through a technical error. Instrumentation and Control (I&C) Supervisors trouble-shooting Channel N42 problems had decided to run response checks on Channel N41 for the purpose of comparison. One Supervisor was unaware that changing the Channel top to bottom detector difference current could depress the Over-Power Delta "T" trip setpoint to the point where a trip could occur with the Reactor at only 3 percent power. The other Supervisor was unaware that the flux difference entered the setpoint calculation. With the trips still in on Channel N42, the trip of Channel N41 satisfied the Reactor Protection System logic, yielding the Reactor Trip.

The second shift S.W.S. notified the O.C.C. and the C.O.E., now on site, of the trip. The C.O.E. and P.M. concurred in the S.W.S.'s recommendation to restart the Plant, based on their confidence that no safety issue was involved.

The S.W.S. subsequently notified the NRC Duty Officer of the Reactor Trip.

As the Plant was being restarted, the P.M. was informed that the problem with Channel N42 had now been isolated to the detector and/or cables within the Vapor Containment, that spare parts were available, that repairs would only take several hours, that operation with one Channel inoperable required daily flux maps with the attendant wear of the Incore Instrument System, and the increased probability of a spurious Reactor trip operating with the now required one out of three trip logic. Based on the projected load demand for the weekend and the fact union personnel would assist in the repairs if the Reactor were shutdown, the P.M. directed the C.O.E. to shutdown. The C.O.E. entered the Control Room as the Reactor went critical and directed the S.W.S. to place the Plant in hot shutdown and prepare for Vapor Containment entry. The S.W.S. caused the Reactor to be shutdown shortly after 10:00 AM.

Preparations for Vapor Containment entry began immediately. The seven man entry team included the I&C Engineer and the I&C Supervisors. Upon the discovery that the Vapor Containment lights were out on the upper floors, that Fan Cooler Unit (F.C.U.) No. 22 was leaking and that the Vapor Containment Floor was covered with several inches of water, the entry team left the Containment and the I&C Engineer notified the Control Room and the P.M. of the conditions found.

After a change of anti-contamination clothes to accommodate the presence of water on the floor, the entry team again entered the Vapor Containment, intent on replacement of the Channel N42 Detector. The team found the water on the floor deeper inside the Vapor Containment Missile Shield, water flowing from all four of the F.C.U. condensate weirs which they passed, and a hot-humid vapor exiting the top of the Nuclear Instrument Channel Detector Well. During the period the entry team was inside the Vapor Containment, the S.W.S. directed the Support Facility Supervisor (S.F.S.) to enter the Vapor Containment and investigate problems identified by the entry team.

The entry team exited the Containment about 2:00 PM, notified the Control Room and P.M. of their findings and inability to replace the detector, and met in the P.M.'s office to discuss the situation.

(It appears that neither the C.O.E. or licensee management above the P.M. were made aware of the observation of steam vapor rising from the Detector Well, until several days later). During the meeting, the Technical Engineering Director (T.E.D.) asked what level of water had been observed. When informed that the level was 2 to 4 inches, the T.E.D. reportedly indicated that since the water had not approached the height of the 6 inch curb around the accesses to the Reactor Vessel Pit, that flooding of the Pit could not have occurred. In response to his question, the P.M. was assured that operations (the S.F.S.) was investigating the problem. It was agreed that the T.E.D. would inform the NRC Resident Inspector of the identified problems.

The S.F.S., now in Vapor Containment, had found both Vapor Containment Sump Pumps inoperable, had started one by righting its float and started the other by replacing its fuses, had identified the major leak on F.C.U. #22 to be from the Service Water Return Line, and thought he had verified that at least one Reactor Vessel Pit Sump Pump was running (the indicating light he examined and found lit means that moisture had entered the upper seal on the motor cables).

The S.F.S. exited Containment to get tools to remove Service Water Return Line Insulation and inform the Control Room of his findings. He then returned to the Vapor Containment, removed the Service Water Return Line Insulation and pinpointed the leak, identified a number of other F.C.U. leaks, and verified the Vapor Containment Sump Pumps were working.

During the second shift, the C.O.E. simultaneously held the position of S.T.A. and C.O.E. This dual roll had him responsible for making decisions and directing operations important to commercial operations, at the same time he was responsible for the independent and detached observation of operations, as an individual dedicated to plant safety. (That one of the S.T.A.'s in training could have been called to the Control Room during this period is not questioned. The fact is that one was not called and the flooding event was not recognized for what it was by the individual assigned that responsibility). (This item is addressed further in paragraph 5).

Around 3:00 PM, the T.E.D. attempted to reach the NRC Resident Inspector, found him not in the office, and left a message on his telephone answering machine to please return the call. He did not mention the subject of his call, but reportedly intended to inform the Resident of the failure of a Main Steam Isolation Valve to fully close earlier that day (the T.E.D. had previously determined that to be reportable under the licensee's Technical

Specifications for 30 day reports) and that some Service Water from F.C.U. leaks had been found on the Vapor Containment Floor.

Later that afternoon, during a telephone conversation, the V.P.-Power Generation was informed of the events of the day by the P.M. Although the fact that F.C.U. leaks had been identified was mentioned, it is unclear that the presence of water on the floor was discussed at this time. The fact that the Plant was shutdown and that F.C.U. leaks were being repaired was subsequently discussed by the V.P.-Power Generation with the President later that evening.

Shortly after 6:00 PM, the S.F.S. returned to the Vapor Containment and at the request of the C.O.E., checked to see if there was any water in the Reactor Vessel Pit. The S.F.S. found the Reactor Vessel Pit to be flooded to within 4 feet of the elevation 46 feet floor grating. The S.F.S. subsequently left the Containment and informed the C.O.E. and the third shift S.W.S. of his findings. (No one connected this observation with a potential submerged condition of the Reactor Vessel, each believing the Reactor Vessel Lower Head was at a significantly higher elevation. Therefore, no one checked elevation drawings to resolve the concern, which should have existed). Before leaving the site for home, the C.O.E. called the P.M. at home to inform him of the condition of the Reactor Vessel Pit. It is unclear whether the observed flooding level was communicated. (The P.M. apparently did not pass this information on to the V.P.-Power Generation). The C.O.E. directed the S.W.S. to pump the water from the Vapor Containment Floor and the Reactor Vessel Pit. The C.O.E. left night orders directing the S.W.S. to continue preparations for a Plant startup.

The S.W.S. subsequently directed efforts to obtain and install submersible pumps in the Reactor Vessel Pit and repair leaking F.C.U.s.

(2) <u>Saturday - 10/18/80</u>

The first shift S.W.S. succeeded in having a submersible pump installed in the Reactor Vessel Pit and had some success in reducing the water level. Efforts continued to prepare for an eventual Reactor startup, now predicted for 9:00 AM, that morning.

The second shift S.W.S. informed the O.C.C. around noon that the Reactor would be critical at about 2:00 PM, that day. Subsequently he toured the Vapor Containment, found a leak on a Steam Generator Blowdown Line, a leak on another F.C.U. and a need to lower the

Reactor Vessel Pit Portable Submersible Pump to ensure it was able to pump out the rest of the water. Upon exiting the Containment, he informed the C.O.E. of his findings.

The C.O.E. called the P.M. at home, informing him of developments. The P.M. subsequently informed the V.P.-Power Generation of the discovery of the leak on the Steam Generator Blowdown Line. Apparently, the P.M. again failed to mention the water in the Reactor Vessel Pit.

Subsequently, the Outage Coordinator called the O.C.C. at about 4:00 PM, informing the watch stander that the Unit would be delayed in its return to power and requesting assistance in locating welders qualified to repair the Steam Generator Blowdown Line leak.

(3) Sunday - 10/19/80

The first shift S.W.S. succeeded in lowering the Reactor Vessel Pit Portable Submersible Pump about 5 feet. Little if any water had been removed since noon, the day before. It subsequently was determined that the pump had siezed and required replacement.

The second shift S.W.S. toured the Vapor Containment, found little if any water had been removed within the last 24 hours, and found one Vapor Containment Float Controller cocked. Subsequent discussion between the S.W.S. and the C.O.E. identified a potential for a siphon path from the Vapor Containment Sump to the Reactor Vessel Pit, using the Reactor Vessel Pit Sump Pumps' common discharge line. It was agreed to drill a hole in the line above the Vapor Containment Sump to provide Reactor Vessel Pit Sump Pump flow indication and an anti-siphor vacuum breaker.

The V.P.-Power Generation called the O.C.C. at about noon to determine the status of the Power Generation System. He subsequently called the S.W.S. and was informed of the problem in pumping the water from the Reactor Vessel Pit. The V.P.-Power Generation was not aware that F.C.U. water had flooded the Vapor Containment, thought the water in the Pit was fresh water from the Steam Generator Blowdown Line leak, and offered assistance in locating pumps to assist in the effort. (It is not clear if the current Pit water level was discussed at this time; but even if it had been, the level was now below the Reactor Vessel and the V.P.-Power Generation believed the water to be fresh).

During the evening, the C.O.E. and P.M. decided to restart the Plant once the F.C.U. leaks were repaired and the water had been pumped below the Incore Instrument Conduits. (Although both men were aware of the Chloride content of the river water which had flooded the Reactor Vessel Pit, and the fact that the Conduits were made of Stainless Steel, neither was concerned with the potential for Chloride Stress Corrosion, since both realized an elevated temperature was required and that only the last couple of feet of the conduit, immediately under the Reactor Vessel, reached these temperatures. Again, the lack of perspective as to the elevation of the bottom of the Reactor Vessel Lower Head, had failed to sensitize them to a real concern).

The third shift S.W.S. had operators install a second Reactor Vessel Pit Portable Submersible Pump. The first Pump was now working, but improper connections prevented the second Pump from being effective.

(4) Monday - 10/20/80

The first shift S.W.S. learned he was to restart the Plant once the F.C.U. leaks were repaired and the Reactor Vessel Pit water level was below the Incore Instrument Conduits. At 5:30 AM, he informed the O.C.C. that the shift was closing the Vapor Containment in preparation for return to power. Prior to watch relief, the S.W.S. informed the O.C.C. the Reactor was critical.

The T.E.D., returning from a weekend off, reviewed logs about 7:30 AM and learned of the flooded condition of the Reactor Vessel Pit. The logs did not indicate water level, but clearly implied the Incore Instrument Conduits had been submerged.

The Manager - Nuclear Power Generation (N.P.G.), returning to site from a weekend plus two day vacation period, independently learned through log review and discussing with personnel of the flooding of the Reactor Vessel Pit. His concern for the potential of Chloride Stress Corrosion of the Incore Instrument Conduits was reinforced by the same concern of the T.E.D. A meeting was held between the Manager - N.P.G., the P.M. and the C.O.E. to discuss Plant status at about 8:30 AM. Based on these discussions, the Manager - N.P.G. decided to place the Plant in hot shutdown and verify that no damage had occurred. The Manager-N.P.G. called the V.P.-Power Generation, informed him of his concerns and decision, and received the V.P.'s concurrence in his decision to shutdown. The Manager - N.P.G. directed the T.E.D. to notify the NRC Resident Inspector. The C.O.E. went to the Control Room and directed the Plant be placed in hot shutdown.

Subsequently, the T.E.D. attempted to return the 8:00 AM return call of the NRC Resident Inspector, responding to the Friday message on the answering machine, and to fulfill the direction given him by the Manager - N.P.G. Telephone contact was finally made at about 11:30 AM, when the T.E.D. informed the Resident that some water had been found on the Vapor Containment Floor over the weekend and that the Plant had been critical earlier that morning, but was now in hot shutdown.

At about noon, the Assistant V.P.-Engineering and the V.P.-Engineering were informed of the Manager - N.P.G.'s concerns. Site management had already initiated swipe surveys of Incore Instrument Conduits (to determine flooding and residue contamination levels), calculations to quantify the water pumped from the Vapor Containment and studies to develop water volume versus flooding elevation data. Corporate Engineering duplicated some of the latter site efforts and initiated calculations to bound the effects of the flooding event.

During the late afternoon, the Manager - N.P.G. responding to an NRC telephone inquiry, explained the licensee's plans and indicated the licensee's belief that the Reactor Vessel had not been wetted.

Later that afternoon at about 5:20 PM, the P.M. and T.E.D., responding to another NRC telephone inquiry, committed to notify NRC four hours prior to any restart. The licensee maintained and believed his waste water volume calculations supported his contention the Reactor Vessel had not been wetted. (It should be noted that these calculations were being performed by the C.O.E. and at least one other individual. Why the C.O.E. did not remember the S.F.S.'s initial water level observation report and recognize that this water level meant the Reactor Vessel had been wetted, has not been determined. The S.F.S. was not involved in these calculations, had no reason to believe the Reactor Vessel had been wetted, knew others more senior then he were aware of his observation if he even thought about it, and just had no reason to independently do the research to determine if his knowledge was critical to the resolution of the licensee's problem).

(5) Tuesday - 10/21/80

The licensee continued inspections, calculations and studies initiated earlier to resolve concerns raised relative to the potential for wetting of the Reactor Vessel and the submergence of the Incore Instrument Conduits in river water. Initial results were encouraging, but not conclusive.

The licensee continued to perform precritical checks, but by early afternoon the Manager - N.P.G. decided to proceed to cold shutdown to enable more thorough examination, and if necessary, cleaning of the Reactor Vessel.

At about this time, the Manager - N.P.G., responding to the solicitation of NRC, committed to meet the requirements of Immediate Action Letter IAL 80-41.

(6) Wednesday - 10/22/80

The licensee's earlier efforts continued.

(7) Thursday - 10/23/80

The licensee's earlier efforts continued.

At about 7:30 AM, licensee management met with the NRC Investigation Team to explain the scope and status of their efforts and learn of the intent of the Team, its needs and required support.

The second shift S.W.S., returning from a period of 72 hours off, found the Plant in cold shutdown. When he had left on Monday, it had just returned to power. Reports of Reactor Vessel Pit water level, observed by three of his operators, who installed the first Portable Submersible Pump on Saturday morning, were rediscovered early that afternoon. The S.W.S. communicated this information to the V.P.-Generation, who then in turn, notified the NRC Investigation Team of the reported information and the names of the individuals.

(8) Friday - 10/24/80

The licensee's earlier efforts continued. Early in the morning, it was positively determined that the residue on the Reactor Vessel was from boiled river water. The V.P.-Power Generation called the NRC Investigation Team of this finding.

At approximately noon, the licensee met with the NRC Investigation Team and reported their conclusion that the Reactor Vessel had been submerged in river water to a depth of about 9 feet, while in hot shutdown.

b. Findings

The Plant Manager is the Chairman and the Chief Operations Engineer is a permanent Member of the Station Nuclear Safety Committee. Technical Specifications 6.5.1.6 requires in part, that "the Station Nuclear Safety Committee shall be responsible for: ...Review of facility operations to detect potential safety hazards." The Station Nuclear Safety Committee did not review, prior to a reactor startup on October 20, 1980, the potential safety hazards associated with the flooding event of October 17, 1980, during which the hot reactor vessel and various stainless steel components were wetted with cold, high chloride river water. This is an item of noncompliance (50-247/80-19-01).

5. Shift Technical Advisor

a. References

-- NUREG-0578, TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations

-- Letter dated 9/13/79 from D. G. Eisenhut, Acting Director, Division of Operating Reactors to All Operating Nuclear Power Plants, titled, "Followup Actions Resulting From the NRC Staff Reviews Regarding the Three Mile Island Unit 2 Accident"

-- Letter dated 10/30/79 from H. R. Denton, Director, Office of Nuclear Reactor Regulation to All Operating Nuclear Power Plants, titled, "Discussion of Lessons Learned Short-Term Requirements"

-- Confirmatory Order dated 2/11/80 from H. R. Denton, Director, Office of Nuclear Reactor Regulation to Consolidated Edison Company of New York, Inc.

-- Letter dated 9/5/80 from D.G. Eisenhut, Director, Division of Licensing to All Licensees of Operating Plants and Applicants for Operating Licenses and Holders of Construction Permits, titled, "Preliminary Clarification of TMI Action Plan Requirements"

-- OAD-9, Revision 3, Indian Point Station, Operations Subsection Administrative Directive, titled, "Operations Subsection Organization"

b. Requirements

(1) NUREG-0578 documented the Lessons Learned Task Force recommendation to establish the position of the Shift Technical Advisor (S.T.A.). The key elements of this recommendation are listed below.

(a) Provide on shift a technical advisor to the shift supervisor with a technical degree, or its equivalent, and with specific training in the plant's response to off normal conditions and accident assessment.

(b) Assign the S.T.A. normal duties pertaining to the engineering aspects of assuring safe operation, including the review and evaluation of operating experiences.

In discussing the purpose of the recommendation, NUREG-0578 provided the following additional clarifications.

(c) That additional technical and analytical capability, dedicated to concern for the safety of the plant, needed to be provided in the control room to support the diagnosis of off-normal events and to advise the shift supervisor on actions to terminate or mitigate the consequences of such events.

(d) When assigned as S.T.A., the individual is to have no duties or responsibilities for manipulation of controls or command of operations.

(e) Consideration should be given to the need to license the S.T.A.'s.

(2) By letter to all licensees dated 9/13/79, the requirement for the establishment of the S.T.A. position was issued. Licensees were required to have the S.T.A. on duty by 1/1/80, and to have S.T.A. training completed by 1/1/81. In discussing alternatives to the Shift Technical Advisor, the two principal functions intended to be accomplished and the characteristics thought to be necessary to effectively accomplish these functions were further defined.

(a) Accident Assessment Function

-- The tentative training and education requirements were explained.

-- The need for the S.T.A. to be detached and independent of operations and commerical pressures was emphasized.

-- The need for the S.T.A. to be within ten minutes of the control room was first introduced.

(b) Operating Experience Assessment Function

-- The need for the individuals performing the function to possess the same independence from operations and commercial pressures as the S.T.A. was emphasized.

-- The need for the group performing this function to possess a diverse technical knowledge base encompassing all areas important to safety was defined.

(3) By letter to all licensees dated 10/30/79, clarification of the requirements for the S.T.A. position were issued. Included in these clarifications were the following key points.

(a) The responsibility to perform the two defined functions of the S.T.A. could be split, if it could be demonstrated the persons assigned the accident assessment function were aware, on a current basis, of the work being done by those reviewing operating experience.

(b) To assure that the S.T.A. would be dedicated to concern for plant safety, the assigned individuals must have a clear measure of independence from duties associated with the commerical operations of the plant. Further, "it is not acceptable to assign a person, who is normally the immediate supervisor of the shift supervisor to S.T.A. duties..."

(4) By confirmatory order dated 2/11/80, the licensee was ordered to establish and man the S.T.A. position within 90 days.

(5) By letter to all licensees dated 9/5/80, NRC confirmed the requirements of the 10/30/79 letter.

(6) The licensee's Administrative Directive No. OAD-9 describes the structure of the Operations Subsection, its functioning and the duties and responsibilities of assigned personnel.

(a) Paragraph 2.0 established the Chief Operations Engineer as the immediate supervisor of the Senior Watch Supervisor, the licensee's position title for a shift supervisor.

(b) Paragraph 6.5 establishes the responsibilities and authorities of the S.T.A. as:

-- To be on shift at all times within 10 minutes of the Control Room;

-- To act as an advisor to the Senior Watch Supervisor regarding the safe operation of the plant during accident conditions; and,

-- To at no time be responsible for the manipulation of reactor controls.

(c) Paragraph 7.4 establishes the major job functions and responsibilities of the S.T.A. as:

-- To act as an advisor to operations personnel;

-- To provide technical and analytical support to the Senior Watch Supervisor;

-- To review logs and records;

-- To review and evaluate day to day operations from a safety point of view;

-- To review and evaluate operating experience;

-- To review and evaluate operating experience of plants of similar design;

-- To provide evaluation of plant conditions required for maintenance and testing;

-- To provide evaluations of the adequacy of procedures;

-- To coordinate activities during major outages; and,

-- To continuously expand their technical knowledge and operational experience.

c. <u>Results of Investigation</u>

The licensee has hired and is in the process of training eight individuals for the S.T.A. position. The S.T.A. trainees function as qualified S.T.A.s during weekend and back shifts. Weekday S.T.A. shift coverage is provided by other licensee personnel, reportedly satisfying S.T.A. training and education requirements. S.T.A. trainee instruction is conducted in the classroom and simulator during weekday sessions. Formal training requirements for the S.T.A. trainees were scheduled to be completed on 11/21/80. No attempt was made during this investigation to determine the acceptability of the educational background or training of the assigned S.T.A.'s.

Interviews of the S.T.A.'s, on shift from 11:00 p.m. on 10/16/80 to 7:00 a.m. on 10/20/80, and others indicate:

-- That each S.T.A. is knowledgeable of his OAD-9 assigned responsibilities, authorities and job functions;

-- That shift relief between S.T.A.'s is performed without benefit of logs or turnover sheets;

-- That a significant part of the S.T.A.'s time is currently spent in furthering their training;

-- That S.T.A.'s are not always called to the Control Room when problems are identified;

-- That the S.T.A.s' lack of confidence in their own knowledge and abilities compounded by the same lack of confidence in the S.T.A.'s by operations personnel, has prevented the realization of the, full potential for safety improvement expected from the S.T.A.'s (reportedly this situation is improving);

-- That the S.T.A.s' sense of responsibility to remain within ten minutes of the Control Room or for reviewing plant conditions to verify the plant is safe, diminishes significantly once the plant is shutdown;

-- That operations personnel will utilize S.T.A.'s for routine activities not involving engineering review or evaluation of plant safety, once the plant is shutdown;

-- That each S.T.A. was aware during his shift(s) that maintenance was repairing leaks on the Fan Cooler Units;

-- That some S.T.A.'s were aware, during their shifts, that water had been found in the Reactor Vessel Pit, but that none had a feel or concern for the quantity of water, that the Vessel might be wetted, or that the Incore Instrument Conduits might be subject to Chloride Stress Corrosion; and,

-- That none had, on their shift, evaluated the propriety of a return to power when it occurred twice on 10/17/80 and once on 10/20/80.

Further, it was learned the Chief Operations Engineer acted as the S.T.A. on Friday, 10/16/80, from 7:00 a.m. to 3:00 p.m. Since the Chief Operations Engineer is the immediate supervisor of the Senior Watch Supervisor, this is a violation of the 10/30/79 criteria for the S.T.A.; specifically, that it is unacceptable that the immediate supervisor of the shift supervisor be assigned as the S.T.A. This last fact is an item of noncompliance (50-247/80-19-02).

d. <u>Recommendation</u>

Of particular concern to the investigators was the apparent acceptance by everyone interviewed, that a timely, detached and independent evaluation of off-normal conditions was not required if the plant was now shutdown or the trip did not result in obvious indicators of an accident condition.

The investigation team recommends that each licensee be required to maintain the S.T.A. position in all modes of operation, including refueling and cold shutdown, with specific prohibitions against the use of S.T.A.'s for other duties supporting Plant operations while on shift.

e. Unresolved Items

Based on the investigation's limited event oriented review of the performance and activities of the S.T.A., a comprehensive conclusion as to the adequacy of the licensee's overall S.T.A. program could not be drawn. The licensee is committed to provide to the NRC, by 12/22/80, a comprehensive "Shift Technical Advisor Performance and Activities Evaluation Report," which will:

(1) Provide an assessment of the adequacy of the performance and activities of the Shift Technical Advisor, on shift from 11:00 p.m. on 10/16/80 to 3:00 p.m. on 10/20/80, as compared to licensee directives;

(2) Provide an assessment of the adequacy of licensee directives as compared to NRC philosophies defined in documents received prior to 10/16/80; and,

(3) Provide a description of changes planned in the use of the Shift Technical Advisors.

This item (50-247/80-19-03) is unresolved.

6. Reporting

a. References

-- 10 CFR 50.72, Notification of Significant Events

-- Technical Specification (T.S.s) Section 6.9.1.7, Reportable Occurrences

-- SAO-125, Indian Point Station, Station Administrative Order No. 125, Revision 2, Station Reporting Requirements

-- SAO-124, Indian Point Station, Station Administrative Order No. 124, Revision 8, Reporting of Anomalous Conditions

-- Memorandum, Chief Operations Engineer to All SWs's, SRO's, RO's, dated 3/6/80, titled "Notification of Significant Events"

-- Significant Occurrence Reports, SOR #80-162 through #80-179

b. Requirements

(1) 10 CFR 50.72(a) requires each licensee of a nuclear power reactor" ...shall notify the NRC Operations Center as soon as possible and in all cases within one hour by telephone of..."

(3) Any event that results in the nuclear power plant not being in a controlled or expected condition while operating or shut down...(and)

(7) Any event resulting in manual or automatic actuation of Engineered Safety Features, including the Reactor Protection System..."

(2) T.S. 6.9.1.7.1 requires the licensee to report by telephone within 24 hours of identification, and confirm in writing, to the Director of Region I or his designate no later than the first working day following identification, the following events:

"(c) Abnormal degradation discovered in fuel cladding, reactor coolant pressure boundary, or primary containment";

"(e) Failure or malfunction of one or more components which prevent, or could prevent, by itself, the fulfillment of the functional requirements of system(s) used to cope with accidents analyzed in the FSAR"; and,

"(i) Performance of structures, systems, or components that require remedial action or corrective measures to prevent operation in a manner less conservative than assumed in the accident analyses in the FSAR or technical specification bases; or discovery during plant life of conditions not specifically considered in the safety analyses report or technical specifications that require remedial action or corrective measures to prevent the existence or development of an unsafe condition."

(3) SAO-125, Revision 2, requires "the Technical Engineering Director shall assure that the NRC is notified in accordance with the Technical Specifications and SAO-124."

(4) SAO-124, Revision 8, requires:

"...the Senior Watch Supervisor to perform the required notifications of 10 CFR 50.72,...and,

"...the Chief Operations Engineer to notify the Technical Engineering Subsection upon identification of a Technical Specification Reportable Occurrence, and the Technical Engineering Subsection to notify the NRC, as appropriate."

(5) Licensee's Memo dated 3/6/80, requires the NRC Resident Inspector be notified of significant events at his office, or if unavailable, at his home.

c. Results of Investigation

(1) The licensee documented the 10/17/80 failure of Nuclear Instrument Channel N42 on SOR #80-174. The S.W.S. recommended the event be reportable under Technical Specification requirements for 30 day notifications. The C.O.E. and T.E.D. concurred in this recommendation on 10/18/80 and 10/22/80, respectively.

(2) The licensee documented the Turbine runback and the first 10/17/80 Reactor trip on SOR #80-175 and SOR 80-176, respectively. The S.W.S. recommended the runback not be reportable. The S.W.S. recommended the Reactor trip be reportable under 10 CFR 50.72, and informed the NRC Duty Officer of both the runback and the trip within one hour of each events occurrence. Neither the C.O.E. or T.E.D. took exception to the S.W.S.'s recommendations, during their documented review on 10/18/80 and 10/22/80, respectively. The T.E.D. notified the NRC Resident Inspector of the events of the morning at about 8:30 AM on 10/17/80.

(3) The licensee documented the second 10/17/80 Reactor trip on SOR #80-177. The S.W.S. recommended the trip be reported under 10 CFR 50.72, and informed the NRC Duty Officer of the trip within one hour of the event. The event was reviewed by the C.O.E. and T.E.D on 10/17/80 and the review documented on 10/24/80, with no exceptions taken to the S.W.S.'s recommendation. The T.E.D. discussed the second Reactor trip with the NRC Resident Inspector at about 9:30 AM on 10/17/80.

(4) The licensee documented the 10/17/80 discovery of water on the Vapor Containment Floor, F.C.U. leakage, and Sump Pump failures on SOR #80-178. The S.W.S. recommended the event be reportable under Technical Specification requirements for 30 day notification. The C.O.E. reviewed the SOR on 10/18/80 and did not take exception to the recommendation. The T.E.D. determined in his review on 10/22/80, that the event was not reportable in itself, but only as a result of its significance in the failure of the Nuclear Instrument Channel N42.

Although the Vapor Containment Floor routinely has wet areas, due to leaks and the dumping of Fan Cooler Unit condensate on the floor, the floor troughs, sump and Vapor Containment Sump Pumps normally keep the majority of the floor dry. The flooded condition of the Vapor Containment Floor was not expected, as evidenced by the need of the initial Vapor Containment entry team to add rubber boots to their anti-contamination clothing, before attempting a second entry. The licensee's failure to report the discovery of this event (the simultaneous presence of multiple Fan Cooler Unit leaks and the existence of an inoperable condition of both Vapor Containment Sump Pumps), which lead to the unexpected condition (major flooding of the Vapor Containment Floor), to the NRC Operations Center within one hour (by 2:30 P.M. on 10/17/80), is a noncompliance with 10 CFR 50.72(a)(2).

Although Fan Cooler Unit leaks were common, the number and volume of the leaks discovered on 10/17/80 cannot be considered normal. Eyewitness accounts of the flow from at least 4 Fan Cooler Unit Weirs, describe the flow appearance from each as that from a garden hose. That the licensee recognized the importance of fixing these leaks is indicated by the direction to plant operators to restart the plant after the leaks were repaired and the Reactor Vessel Pit dry. The licensee's failure to promptly report to NRC within 24 hours (by 10/18/80), the abnormal degradation discovered in primary containment (the Fan Cooler Unit Cooling Coils and Service Water Piping), is a noncompliance with T.S. 6.9.1.7.1.c.

The fortunate discovery on 10/17/80 of the leakage from the Fan Cooler Unit Service Water System and the presence of a large accumulation of water (about 100,000 gallons) on the Vapor Containment Floor, invalidated design assumptions of the flooding level expected in the Vapor Containment during a Design Basis Loss of Coolant Accident. Had the licensee not chosen to shutdown to make a Vapor Containment entry on 10/17/80, to repair the failed Nuclear Instrument Channel Detector, the water accumulating in the Vapor Containment Floor and, as a result the potential accident water level, could have gone much higher before the plant would have been forced to shutdown. The resulting accident water level had the potential for preventing the Recirculation System from fulfillment of its functional requirements by flooding out the Recirculation Pumps located in the Vapor Containment. The licensee's failure to promptly report to NRC within 24 hours (by 10/18/80), the multiple failures of the Fan Cooler Unit Service Water System pressure boundary and the inoperability of the Vapor Containment Sump Pumps, which could have prevented by themselves the fulfillment of the functional requirements of the Recirculation System during a Design Basis Loss of Coolant Accident, is a noncompliance with T.S. 6.9.1.7.1.e.

(5) The licensee documented the 10/17/80 discovery of the failure of Main Steam Isolation Valve, MS-1-23, to close automatically on SOR #80-179. The S.W.S. recommended the event be reportable under Technical Specification requirements for 30 day notification. Neither the C.O.E. or T.E.D. took exception to the recommendation during their review on 10/18/80 and 10/22/80, respectively.

The T.E.D. intended to inform the NRC Resident Inspector of the failure of the M.S.I.V. and the discovery of some water on the

Vapor Containment floor, when he tried to contact the Resident at about 3:20 P.M. on 10/17/80. When he was unsuccessful in establishing that contact, he left a message on the Residence's answering machine, requesting a return call. Since the Resident had already left the site, with express permission of his supervision, that return call was not made until the morning of 10/20/80. The T.E.D. finally reestablished contact with the NRC Resident Inspector about 11:30 A.M. on 10/20/80, when the information then known by the T.E.D. was discussed.

(6) The discovery, during the evening of 10/17/80, that the Reactor Vessel Pit had been flooded to within four feet of the elevation 46 feet floor, was not documented by the licensee during the 10/17-20/80 weekend. This flooding elevation in the Pit corresponded to a water level on the outside of the Reactor Vessel itself of about 8½ feet. The submergence of the Reactor Vessel and the Incore Instrument Conduits in cold, high chlorides, River Water, while at normal operating temperatures of about 550°F, is a condition not considered in the safety analysis report or technical specifications and did require corrective measures, the removal of the water and boildown residue plus nondestructive examinations of the Reactor Vessel and the Conduits, to prevent the development of an unsafe condition. The licensee's failure to promptly report to NRC within 24 hours (by 10/18/80) the discovery of the flooded Reactor Vessel Pit is a noncompliance with T.S. 6.9.1.7.1.i.

d. Conclusion

The three noncompliances documented above, each explain why the licensee should have promptly reported the Vapor Containment flooding event. Since each is only example of the rationale the licensee could have used to report the basic event, the three are combined into a single item of noncompliance with three examples (50-247/80-19-04).

7. Reactor Trips and Instrumentation

a. General

The inspector held discussions with key plant personnel and reviewed operating logs to determine the cause of the two Reactor trips, which occurred on October 17, 1980.

b. Turbine Runback

At 12:30 a.m. on October 17, 1980, a control room operater noticed the Nuclear Instrumentation (NI's) Channel readings did not appear normal. This was discovered while performing the daily heat balance. A quadrant power calculation was performed to assure power distribution was correct. The calculation produced two apparent abnormalities; 1) the quadrant tilt was 1.0240 at the top of the Core and 1.0363 at the bottom (Technical Specifications limits the quadrant tilt value to 1.02); and, 2) power appeared to be excessive in the top of the Core in the Channel N42 quadrant. At this point, the operators began to plot axial tilts.

The Turbine load was decreased to reduce Reactor power, in an attempt to reduce the quadrant power tilt, and Reactor power was stabilized at 90 percent. The operators suspected Channel N42 was failing. I&C personnel on site were requested to perform a functional test of the Channel. The Reactor Engineer was called to the site and an incore flux map was obtained. After a review of the incore flux map, the Reactor Engineer declared Channel N42 inoperable. The operators then obtained the Emergency Procedure for Nuclear Instrumentation Malfunction, assumed the Channel had already failed, and proceeded to perform the "Subsequent Action" portion of the procedure, without first verifying the "Immediate Operator Action" portion of the procedure had been satisfied. Had the operators performed the required immediate action, they would have reduced power below 70 percent power before deenergizing the channel. When the Control Power fuses were pulled by procedure, the rapid decrease of indicated power on Channel N42 appeared to the protection system as a dropped rod, and caused a Turbine runback to 70 percent power.

c. First Reactor Trip

The Control Rods were being operated manually and did not step in automatically during the Turbine runback. The existing Core axial flux distribution was now outside its program band. Average coolant temperature (Tavg) began increasing with the load/power generation mismatch. The use of Control Rods to correct the Tavg problem would have further aggravated the Core axial flux distribution problem. It was decided to increase the Turbine load to correct both the Tavg and flux distribution problems.

The governor valves on the Turbine were closed to a controlling position from the control room, taking control of the Turbine away from the load limiting valves, which were holding power at 70 percent. Communication was set up between the Control Room and a Nuclear Plant Operator (NPO), who had previously been instructed on how to perform the evolution of opening the load limiting valves. The NPO turned the valves in the wrong direction as a result of a combination of human and communication errors. This caused a rapid decrease in Turbine load, causing a momentary shrink in the Steam Generators water level and an increase in Pressurizer pressure, resulting in either a LoLo Steam Generator water level or Hi Pressurizer pressure trip of the Reactor.

d. Second Reactor Trip

The Reactor was subsequently made critical by normal start up procedures and the power level was maintained at about 3 percent. I&C technicians were performing response checks on NI Channel N42. The I&C supervisor noted a sluggish response from the lower detector of Channel N42. Channel N42 was then placed back in service to conduct a comparision response check of Channel N41. All trip functions were restored on Channel N42, with the exception of overpower delta "T" and overtemperature delta "T"; these functions were left in a tripped condition. The supervisor believed there was no danger of lowering the overpower or overtemperature delta "T" trip setpoints, sufficiently to cause a Reactor trip at the existing power level, while the response checks were being performed. When the comparison check on Channel N41 lower detector was attempted, the overpower delta "T" trip setpoint was reduced to the point at which a trip occurred. The simultaneous existence of Channels N41 and N42 overpower delta "T" trip signals satisfied the Reactor Protection Systems 2 out of 4 logic, causing a Reactor Trip.

On 10/17/80, the signal produced by the lower Detector of Channel N42 became erratic. The licensee's investigation concluded the Detector or its cable were grounded. The ground was later attributed, on 10/21/80, to moisture found in the Detector connector. An I&C supervisor concluded that the moisture was a result of operation in a steam vapor environment for which the connector was not designed. The Nuclear Instrument connectors are not water tight, but are wrapped with electrical tape by technicians, to prevent the metal parts from grounding to their metal lined container. No attempt is made by the licensee to make the connections moisture proof. The procedure for installation of a new Nuclear Instrument Detector does not require taping.

e. Nuclear Instrument Channel N42

The Nuclear Instrument Detectors are located on the outside of the Reactor Vessel, in movable Detector holders that facilitate Detector removal and repair.

f. Findings

Technical Specification 6.8.1 requires procedures be followed. The operators' failure to implement the Immediate Operator Action requirement to reduce power to at or below 70 percent, prior to pulling the control power fuses, is an item of noncompliance (50-247/80-19-05).

g. Unresolved Items

At the completion of the on site investigation, it was determined that additional information relative to the trips and performance of instrumentation, were required. The licensee has committed to providing the following documents by 12/22/80:

(1) Reactor Trip Cause Identification System Evaluation Report

-- explaining why the plant computer identified the first 10/17/80 Reactor trip cause as high Pressurizer pressure, while the first out annunciator identified the trip cause as low Steam Generator water level; and,

-- providing rationale for acceptance of this discrepancy or describing how the systems will be upgraded to resolve the problem.

This item (50-247/80-19-06) is unresolved.

(2) Excore Nuclear Instrumentation Evaluation Report

-- providing a description of tests and inspections performed and the results achieved for the excore nuclear instrumentation, following the flooding event;

-- discussing the probable impact on the instrumentation life and reliability; and,

-- justifying continued operation without repair or modifications.

This item (50-247/80-19-07) is unresolved.

(3) Immediate Action Letter No. 80-41 Report

-- providing response required by item (8) of the Immediate Action Letter.

This item (50-247/80-19-08) is unresolved.

8. Containment Sump Pumps and Sump Level Measurement

a. Water Collection

General leakage from fluid systems and condensation in containment collects on the containment floor at elevation 46. The floor is sloped in various directions so that fluids run into troughs and then into the containment sump. The reactor vessel pit is protected from water on the floor by a 6 inch curb. The containment sump is automatically pumped by two Sump Pumps to the Waste Hold Up Tank (WHUT) outside of containment. The WHUT receives liquid waste from many sources in Unit 2 and is in turn sent to the Unit 1 radioactive waste processing systems. The containment sump is about 7 and one-half feet or 90 inches deep.

b. Sump Level Measurement

(1) Description

Containment Sump Level is measured by 10 Gem type, magnetic reed, float switches on two float rods. These switches read out in the control room and are labeled: 1", 7", 45", 51", 91", 97", 139", 145", 151" and 159". Their zero reference is several inches from the bottom of the sump and they are not precisely located in accordance with their inch markings. The general belief among operators, prior to October 17, 1980, was that the 91" light indicated a sump level about an inch or two below the top of the sump. In fact, the 91" float was a few inches above the top of the sump, i.e., the containment floor, but below top of the curb surrounding the reactor vessel pit. Normal sump level varied from above the 7" light to around the 51" light. Prior to October 17, 1980, the sump pumps appear to have cycled-on just above the 51" light and to have pumped the sump down to between the 7" and 45" lights.

There were normally several days between the times that the sump pumps operated. The control room operators log the sump level based on these lights every 4 hours. The log sheets state that the normal reading is greater than or equal to 7". The sump level lights are checked each refueling and were last tested on June 18, 1979.

(2) Performance

Prior to October 3, 1980, indicated sump level had been at 45" for a few days and there were some questions raised by the operators as to whether the sump level lights were operating properly. During a containment entry made on October 3, 1980 to correct an FCU service water leak, the Chief Operations Engineer operated several of the float level switches and containment sump pump #210. The control room later said they saw the level lights flash and the Chief Operations Engineer stated that the sump pump appeared to operate properly. After this entry and until October 17, 1980 the sump level was logged at 51". The 91" light reportedly never came on. This could have been caused by: (a) stuck float switches, (b) a true level just above 51" but below the pump cycle-on point, combined with essentially zero collection in the sump, and/or (c) a true level above 51" and increasing, combined with no sump pump operation. After the plant shutdown on October 17, 1980, the 45", 51" and 91" float switches were operated and the control room lights appeared to operate correctly. During the five months previous to October, 1980, the combination of leakage and condensation going into the sump had never been low enough so that the 51" light remained on long enough to coincide with and to be logged during one of the 6 daily log reading periods. This combination of information supports choice (c) above.

(3) Modifications

One of the recently imposed requirements from the Three Mile Island Lessons Learned Study was for continuous indication in the control room of containment water level, both narrow range and wide range, from the bottom of the containment sump and reactor vessel pit. This was classified as a Category B item, which required implementation by January 1, 1981. The licensee had committed to this requirement and had not yet installed the continuous indicators. Current plans are to install these continuous level indicators both in the containment sump and reactor vessel pit. Details of the modifications will be submitted to NRC by December 22, 1980 and are considered unresolved (Item No. 50-247/80-19-09).

After October 25, 1980, the licensee reset the containment sump pump cycle points so that sump level is maintained between the 7" and 45" lights. Control room annunciators were attached to the 45" and 51" switches and all lights above 45" were changed in color to highlight their significance.

(4) Additional Open Items

Technical Specification 6.8.1 and ANSI N18.7-1972 require that procedures be established to provide an approved, preplanned method of conducting operations. These documents also state that limitations on parameters being controlled and appropriate corrective measures to return the parameter to the normal control band should be specified. Contrary to the above, procedures were not established which would provide for a preplanned method of controlling containment sump level. Specifically, no control band (other than $\geq$7 inches) or maximum sump level was specified, nor were corrective measures for high sump levels detailed. This is an item of noncompliance and is designated Item No. (50-247/80-19-10).

The acceptability of the arrangement of the sump level measurement system is unresolved, due to:

(a) no warning just prior to overflowing the sump, and

(b) level markings which do not correspond to actual levels and which cause operator confusion.

This item is unresolved and is designated Item No. (50-247/80-19-11).

c. Containment Sump Pumps

(1) Description

There are two sump pumps located in the containment sump, #29 and #210. They are Goulds Vertical Sump Pumps, Model 3171 rated at 50 gallons per minute (gpm) each. The motor control center, circuit breakers and pump control switches are located inside containment. There are no controls or direct indications of pump operation outside of containment. The pumps operate automatically using a float ball and switch arrangement. The pumps are tested for operation each refueling outage and were last tested June 18, 1979.

(2) Performance

Sometime prior to October 17, 1980, both containment sump pumps failed to pump when their actuation levels were reached. During containment entries on October 17, 1980, pump #210 was found to have its float rod cocked and stuck in the sump grating. When straightened, the pump started. The fuses of pump #29 were replaced, the thermal overload reset button was pushed and the circuit breaker closed. This pump then started. Several times during the time period October 17 through October 19, 1980, the sump pump float rods and/or float balls were found to be inoperable and were repaired.

One reactor cavity sump pump is powered from downstream of the fuses for containment sump pump #29. It appears that failure of the reactor cavity pump due to overheating at sometime prior to October 17, 1980, caused the fuses for containment sump pump #29 to blow, also.

The licensee has committed to provide the NRC with a detailed failure analysis report on the containment sump pumps by December 22, 1980, which will:

-- provide a description of tests and inspections performed to identify the cause of failures;

-- detail the results of the analysis of failures; and

-- explain why the proposed modified or repaired system is immune to the identified failure mechanisms or why these failure mechanisms are now tolerable.

This item is unresolved and is designated as Item No. (50-247/80-19-12).

(3) Modifications

On October 19, 1980, the licensee added a guide at the top of the sump pump float rods to help prevent sticking of the rod. Further modifications of pump controls and pump instrumentation are planned and details will be submitted to the NRC by December 22, 1980. This item is unresolved (Item No. 50-247/80-19-13).

(4) Additional Open Items

Standard industry practice and the manufacturer's technical manual specify that (a) float rods for operating sump pumps be attached or guided both at the top and the bottom; and (b) the pumps should not be run against a shutoff head. Contrary to the above: (a) the sump pump float rods were not guided at the bottom from October 17 through October 20, 1980; and (b) the pumps were not prevented from running against a shutoff when the containment isolation valves from the containment sump were shut on September 14, 1980, September 15, 1980 and at various times between October 17, 1980 and October 19, 1980 and power to the pumps was not secured. This item is a deviation and is designated Item No. (50-247/80-19-14).

Test procedures PT-R2A, which is utilized to test the operation of the containment sump pumps, does not specify any setpoints for pump operation. The System Description for Liquid Waste Disposal (dated 1973) states that one pump cycles between 30" and 29" and the other pump cycles between 33" and 32". The setpoints for pump operation appear to have drifted up to around 51" due to no specified calibration value. This lack of a calibration value is contrary to Technical Specification 6.8.1 and Regulatory Guide 1.33, Appendix A, paragraph H.1, and is an item of noncompliance (Item No. 50-247/80-19-15).

9. Reactor Vessel Pit Sump Pumps

a. Description

The pit underneath the reactor vessel extends from about elevation 46' down to about elevation 19'. The initial plant design had no provision for pumping water which somehow managed to collect in the pit. During initial preoperational testing a service water line to an FCU failed, resulting in flooding of this pit. As a result of this occurrence, an Engineering Service Request (#238) was initiated on April 14, 1972 to install sump pumps in the pit. These pumps were actually installed during the 1976 refueling outage and pump the reactor vessel pit to the containment sump. The pumps installed are Crane Deming submersible pumps which are designed to operate submerged, not in air. They each have a 100 gallon per minute capacity and a check valve in their discharge. After individual pump check valves the discharge lines tie together, run up to about elevation 52', over to the containment sump and then down to the bottom of the containment sump. No anti-siphon vacuum breaker is included in the line. The motors have a tandem seal design with a moisture detection circuit between the two seals to detect impending or actual motor failure. All controls and the moisture detection alarm lights are inside containment.

b. Performance

During containment entries on and after October 17, 1980, both reactor vessel pit sump pumps were found to have failed. One pump had a failed motor seal, possibly resulting in flooding of the motor. The moisture alarm light did function, although persons observing the light believed it to be a power-on indicator light, at the time. The second pump was noted to have had moisture in its power cable. Both motors were disassembled and inspected by the manufacturer. Reportedly the exact cause of failure could not be determined. The licensee and the manufacturer believe that failure of both motors was caused by overheating, due to running the motors in air for at least 15 to 30 minutes, at some time prior to this incident.

The licensee has committed to provide a detailed failure analysis report to the NRC by December 22, 1980, which will:

-- provide a description of tests and inspections performed to identify the cause of failures;

-- detail the results of the analysis of failures;

-- explain why the proposed modified or repaired system is immune to the identified failure mechanisms or why these failure mechanisms are now tolerable; and,

b. Performance

During containment entries on and after October 17, 1980, both reactor vessel pit sump pumps were found to have failed. One pump had a failed motor seal, possibly resulting in flooding of the motor. The moisture alarm light did function, although persons observing the light believed it to be a power-on indicator light, at the time. The second pump was noted to have had moisture in its power cable. Both motors were disassembled and inspected by the manufacturer. Reportedly the exact cause of failure could not be determined. The licensee and the manufacturer believe that failure of both motors was caused by overheating, due to running the motors in air for at least 15 to 30 minutes, at some time prior to this incident.

The licensee has committed to provide a detailed failure analysis report to the NRC by December 22, 1980, which will:

-- provide a description of tests and inspections performed to identify the cause of failures;

-- detail the results of the analysis of failures;

-- explain why the proposed modified or repaired system is immune to the identified failure mechanisms or why these failure mechanisms are now tolerable; and,

-- explain the significance of the reported moisture found in one pump's power supply cable and the indicated moisture alarm found on the other pump's controller, as impacts on the reported failure mechanisms.

This item is unresolved and is designated as Item No. (50-247/80-19-16).

c. Modifications/Repairs

The two failed pumps were repaired after 11/2/80, by installing new motors and impellers in the original housing, and by replacing the electrical cables. The licensee intends to upgrade the motors so that they can be run continuously in air. On October 18, 1980, a hole was drilled in the common pump discharge line due to concerns about a possible siphon effect from the containment sump to the reactor vessel pit (if the check valves were leaking).

Further modifications of pump controls are planned and details will be submitted to the NRC. This item is unresolved and is designated Item No. (50-247/80-19-17).

d. Additional Open Items

Currently there are no surveillance tests or calibrations associated with the reactor cavity pumps, which would assure their operability. This item is designated Inspector Follow Item No. (50-247/80-19-18).

The temporary vacuum breaker drilled in the pump discharge line has the potential of spraying water on other containment components and has not been shown to be an adequate vacuum breaker. This item is unresolved and is designated Item No. (50-247/80-19-19).

The moisture detection lights for the sump pumps were not labeled and various personnel were not aware of their function. This item is unresolved pending correction of this situation and a review by the licensee to determine if there are other pieces of equipment/indications in the plant, which require better labeling to ensure safe operation (Item No. 50-247/80-19-20).

10. Leak Detection

a. Methods

Technical Specification 3.1.F.1 states that if leakage of reactor coolant is indicated by the means available such as water inventory balance, monitoring equipment or direct observation, then a safety evaluation shall be performed as soon as possible. Technical Specification 3.1.F.2 states that if the indicated leakage is substantiated and is evaluated as unsafe or is determined to exceed 10 gallons per minute, then the reactor shall be shutdown.

The Technical Specification Bases and the Final Safety Analysis Report discuss the various means available for leak detection. These methods include: water inventory balance, containment air particulate monitors, containment radiogas monitors, containment humidity detectors and the Fan Cooler Unit (FCU) condensate flow leak detection system. The only methods sensitive to non-radioactive leakage are the water inventory balance, humidity detectors and FCU condensate flow leak detection system. The current methods of water inventory balance are only regularly used on the primary system. Some attempts have been made at balances on the Waste Hold Up Tank (WHUT), but available instrumentation limits the usefulness of this method for leaks inside containment. The licensee is currently considering installing flow meters and integrators on the containment sump pumps discharge and establishing procedures for related water inventory balances. This item is unresolved pending review of the methods established and modifications made for determining leak rates of non-radioactive water from various systems within containment and is designated as Item No. (50-247/80-19-21).

Additionally, due to problems with the FCU condensate and humidity leak detection systems during this incident, as detailed in subparagraphs b. and c. below, the licensee has committed to submit to the NRC a capability report on these steam vapor leakage detection systems by December 22, 1980, which will:

-- detail the methods to be used and the probable threshold for leak detection, utilizing the existing and planned instrumentation systems;

-- provide copies of approved procedures to implement these methods and identify the intended frequency of use, acceptance criteria and expected response should the acceptance criteria not be met; and,

-- explain why the fan cooler unit weir detection system did not detect the multiple cooling coil leaks and the steaming of the reactor vessel.

This item (50-247/80-19-22) is unresolved.

b. FCU Condensate Leak Detection System

(1) Description

This system collects service water leakage from the coils inside the FCU's and moisture condensed by the FCU's from the containment atmosphere. The leakage or condensate is routed through drains to a normally closed dump valve. Upstream of the dump valve is a standpipe or weir where the water collects and can be measured with a level detector and transmitter. These weir level detectors read out in the control room. Overflow from the weirs or water dumped by the dump valves goes directly to the containment floor on elevation 46', where it is routed to the containment sump. The FSAR gives values for flows which can be measured and states that a high level alarm is provided to warn the operator when operating limits are approached. Prior to October 17, 1980, the alarms were set at about 4" in the weir, which corresponds to about 8 gpm condensate flow, which correlates with a Reactor Coolant System leak rate of greater than 14 gpm. The Technical Specification Bases state that the system provides a dependable and accurate means of measuring leakage, including leakage from the cooling coils themselves, which are part of the containment boundary. SOP1.7, Revision 4, "Reactor Coolant System Leakage Surveillance and Safety Evaluation," is utilized to perform leakage calculations daily, using various means including the FCU weir levels. Additionally, the highest and lowest of the 5 weir levels is recorded each 4 hours on control room logs.

(2) Performance

On October 14, 1980, between midnight and 4:00 a.m., FCU #22 weir level detector alarmed reading about 6.5 inches. The licensee evaluated this as a failed detector, based on the following:

(a) Radiation instruments, humidity detectors and water inventory balance showed no leak. (However the leak apparently was cold, non-radioactive service water);

(b) WHUT inventory balance showed no abnormal increases. (However the containment sump pumps were apparently inoperable, thus the water was not pumped from containment to the WHUT); and,

(c) After securing FCU #22 and isolating service water to it, the weir level stayed high. (However it appears that the service water isolation valves leaked by.)

No additional checks, such as a containment entry to observe conditions, were made by the licensee relative to determining whether the high weir alarm represented a true indication of a leak or a failed instrument.

On October 14, 1980, after several hours reading high, but not off-scale, the weir level detector did go off-scale high. During the containment entry on October 17, 1980, water was observed flowing out of FCU #22 weir and flowing from the ceiling above the weir detector where FCU #22 is located. After service water was isolated to FCU #22, some water was still observed to flow from the weir. On November 3, 1980 during a hydrostatic test of another Fan Cooler Unit, with FCU #22 isolated, about 8,000 gallons of service water leaked back past the servive water outlet containment isolation valves from FCU #22 (SWN44-1) and onto the containment floor through an open spool-piece, where maintenance was in progress. Additionally, during attempts to perform a type "C" leak rate test, required by T.S. 4.4.D.2.b at 52 psig, the licensee was unable to maintain pressure greater than 6 psig. Partial disassembly and visual examination showed that the valve would not fully close. This indicates leakage through valve SWN44-1 in excess of the limits of Technical Specification (T.S.) 4.4.D.2.b. This valve had exhibited high leakage during the 1976 and 1979 outage leak rate testing program and had new modified internals installed in 1979 to address this problem. A report on the service water containment isolation valves will be submitted to the NRC by December 22, 1980. This report will contain:

-- the results of tests and inspections of the installed valves, performed since 10/17/80;

-- a history of the performance of these valves during the life of the plant; and,

-- justification for return to operations with the installed valves.

This item is unresolved and is designated Item No. (50-247/80-19-23).

During repair of the weir level indicator, technicians found water in the level transmitter conduit. When this water was removed, the transmitter indicated correctly. The leak-tight integrity of the weir level indicators is unresolved and is designated Item No. (50-247/80-19-24).

Other weir level indicators showed various non-zero readings throughout the months prior to October 17, 1980. The significance of these readings and the adequacy of the analyses performed on them is discussed below in sub-paragraph (4).

(3) Modifications

The licensee is considering the addition of a conductivity cell in the water flow to the containment sump in order to allow better identification of the source of leakage in containment, either service water or demineralized water.

The licensee has committed to provide a report which will detail and justify all planned modifications by December 22, 1980. This item is unresolved (50-137/80-19-25).

(4) Additional Open Items

Technical Specification (T.S.) 6.8.1 and Regulatory Guide 1.33, Appendix A, paragraphs F.1 and H.2 require procedures be established and implemented for each surveillance required in the Technical Specification. Contrary to this requirement, procedures were not established to satisfactorily implement T.S. 3.1.F.1 regarding determination of leakage from the reactor coolant system (RCS) with the FCU condensate leak detection system.

Specifically:

(a) Procedure SOP 1.7 has no required action level for weir height;

(b) Procedure SOP 1.7 does suggest a level of 2" in a weir and increasing as an action level, but this level could correspond to an already significant RCS leak (between 7 and >14 gpm) and this suggested level was not used when exceeded (e.g., all of September, 1980 data);

(c) The control room logs maximum limit of 4" and the actual alarm setpoint of approximately 4" correspond to an already significant RCS leakage (>14 gpm);

(d) No calibration procedures were established to calibrate or set the high level alarms for the FCU weir level detectors; and,

(e) In SOP 1.7, when evaluating weir levels, it was not clear what to use for initial values (step 4.1.A) or final values (step 4.1.B). Mostly, baseline data from October 25, 1979 was used, but not always. When it was used, due to the length of time passed, it provided a baseline of questionable usefulness.

This item of noncompliance is designated as Item No. (50-247/80-19-26).

Additionally, the inspector noted that past data recorded using the FCU condensate weir level detectors varied noticeably from day to day, apparently due to changing containment conditions. This resulted in the weirs measuring non-zero values, under conditions of no leakage, and varying about 3" in level. This appears to preclude simply resetting alarms to lower levels (as committed to in the FSAR) without introducing many spurious alarms which could possibly distract operators from other more important alarms. Thus careful analysis of the requirements and capabilities of this system is required when addressing the item of noncompliance.

c. <u>Humidity Detectors</u>

(1) <u>Description</u>

Each Fan Cooler Unit (FCU) has a humidity and a temperature detector in the air steam just before entering the cooler. A Foxboro multipoint recorder displays each humidity in the control room. There is a common annunciator which alarms when any detector's dew point exceeds a set value. The temperature and humidity detectors themselves are calibrated each refueling outage. The FSAR states that the humidity detectors are sensitive to vapor originating from all sources within containment and that their sensitivity is on the order of 0.25 gpm per degree Fahrenheit (^{o}F) of dewpoint temperature increase. Procedure SOP 1.7, "Reactor Coolant System Leakage Surveillance and Safety Evaluation" performs leakage calculations daily using various means, including the containment humidity detectors. Additionally, the highest and lowest of the 5 dewpoints is recorded every 4 hours on the control room logs.

(2) Performance

During the two weeks prior to October 18, 1980, the dewpoint detectors were reading as they previously had, namely at or below the bottom of the multipoint recorder's scale, which is 70^{o}F. No response would be expected to the leak of the cold Service Water into containment. On October 18 and October 19, 1980, the dewpoints varied up and down to a maximum of about 88^{o}F, apparently in response to the steam generator blowdown line leak, the steaming of water in the reactor vessel pit while in contact with the reactor vessel, and the operation of different numbers of FCU's. Calibrations performed on 10/25/80 showed that the dewpoint instruments were all reading significantly low.

Based on the above, the response and the calibration interval adequacy of the humidity detection system is unacceptable. The licensee has committed to submit a report on this issued by December 22, 1980, which will do the following:

-- explain the cause of each change in the trend of average dewpoint recordings for the period 11:00 p.m. on 10/16/80 to 3:00 p.m. on 10/20/80;

-- incorporate best estimates of steam generator blowdown line leak flow, start time, containment mixing and stop time;

-- incorporate best estimates of fan cooler unit operations including number in operation versus time, moisture removal capability and service water temperature;

-- incorporate best estimates of reactor vessel water level versus time, steaming rates, containment mixing and location of instrumentation versus source of steam;

-- justify continued operation with a recorder lower limit of 70^{o}F;

-- justify current surveillance frequency which allowed the instruments to become so out of calibration; and,

-- explain why reactor vessel steaming was not detected.

This item is unresolved (Item No. 50-247/80-19-27).

(3) Modifications

Reportedly, no modifications are currently planned for the humidity detection system. A report will be submitted to the NRC which will justify operation with the system as is. The item is unresolved pending submission and review of the report and is designated as Item No. (50-247/80-19-28).

(4) Additional Open Items

Technical Specification (T.S.) 6.8.1 and Regulatory Guide 1.33, Appendix A, paragraphs F.1 and H.2, require procedures be established and implemented for each surveillance required in the Technical Specification. Contrary to this requirement, procedures were not established to satisfactorily implement T.S. 3.1.F.1 regarding determination of leakage from the reactor coolant system (RCS) with the humidity detection system. Specifically:

(a) The Procedure SOP1.7 action level for dewpoint of 89°F and increasing and the control room log sheet maximum dewpoint of 95°F combined with a normal reading of 70°F or lower corresponded to an already significant RCS leakage (>4 gpm);

(b) The humidity detectors were not sensitive to incremental increases of water leakage as described in the FSAR and T.S. Bases, because they were normally off scale low (less than 70°F) as logged on the control room logs for the majority of September, 1980;

(c) No calibration procedures were established to calibrate or set the alarms for the humidity detectors; and

(d) Graph RCS-8, which is used to quantitatively determine an RCS leak rate based on observed dewpoints, is not accurate, since it apparently assumes a baseline dewpoint near 85°F, while actual baseline values are at or below 70°F.

This item of noncompliance is designated as Item No. (50-247/80-19-29).

11. Fan Cooler Units

a. General

The majority of the water which collected on the Vapor Containment floor was River Water from Service Water leaks on Fan Cooler Unit cooling coils and supply piping. The Fan Cooler Units (F.C.U.s) are the heat exchangers for the Containment Cooling and Filtration System. There are five F.C.U.s, numbered 21-25. Each cooling coil assembly consists of 10 units mounted in two banks, one behind the other and stacked five high for horizontal air flow. The heat exchangers are air conditioner type cooling coils consisting of 90-10 Cu-Ni (pipe) headers, 90-10 Cu-Ni stub tubes (nipples), 90-10 Cu-Ni tubes and copper plate type fins. In addition to the large F.C.U. heat exchangers each Unit has a tube and plate type heat exchanger as a motor cooler. The F.C.U. heat exchanger is hard piped to the service water system and the motor cooler heat exchanger is connected to the system with flexible hoses.

The Service Water System supplies the cooling water for the heat exchangers through carbon steel-cement lined pipe. The cooling water is untreated Hudson River Water. The River Water is routinely analyzed by the licensee's chemistry personnel. As with any tidal dynamic river, the chemical composition of the river is affected by upstream and downstream effluents. Due to a recent drought, salt water intrusion has significantly raised the Chloride ion content of the river. A review of the licensee's River Water analysis for the week ending 10/22/80 indicated, in part, a 7.5 - 7.9 pH and 4560 -4600 ppm NaCl chlorides.

b. Leaks

The F.C.U. Service Water leaks can be divided into the following categories:

(1) Localized failure of cement lined carbon steel pipe. This failure mode has been limited to localized general corrosion failures at welded joints, due most probably to improper fit up linings or damage to the lining caused by field welding, possibly accelerated by small anode (Fe) to large cathode (Cu-Ni) galvanic effects.

(2) Stub tube (nipple) to header joint leaks. No information is available to indicate whether the failure mode is related to corrosion or to improper brazed joints (manufacturing defect).

(3) Stub tube on Heat Exchanger tube leaks. No information is available to indicated whether these failures are related to low velocity induced pitting, high velocity erosion, or propagation of incipient tube defects.

(4) Flexible hose failures on the Motor Cooler Heat Exchanger. There is no information available to indicate whether these failures are caused by fatigue or corrosion, however, the most probable cause is fatigue.

c. F.C.U. Status and Maintenance History

The NRC inspector held discussions with site maintenance and corporate engineering personnel to determine if specific failure analysis studies were made on any of the F.C.U. related leaks. No failure analysis has been conducted by the licensee, other than those conducted on cement lined pipe failures. (This deficiency is discussed further under QA/QC Program).

The maintenance records for the fan coolers were reviewed with the Maintenance Engineer. The general maintenance history was discussed with the Assistant Vice President for Engineering and cognizant engineering personnel selected by him. A discussion was held with the Maintenance Engineer following his detailed inspection of the F.C.U.s. Later the NRC inspector conducted a thorough visual inspection of the F.C.U.s, accompanied by the Maintenance Engineer. The report of observations by the Maintenance Engineer of the five F.C.U.s on 10/26/80 indicated 46 previous repair locations (reported in 32 MWR's), and 8-12 current probable leaks. There were 7 currently installed pipe clamps, 8 re-brazed repairs and 18-25 epoxy repairs noted. The 18-25 number results from difficulty identifying general repaired areas as individual or group repairs. A Maintenance Department summary sheet made up from Maintenance Work Request (MWR) records indicates 3 repairs on F.C.U. #21, 3 on F.C.U. #22, 9 on F.C.U. #23, 7 on F.C.U. #24 and 10 on F.C.U. #25. The total of 32 "MWR repairs" includes some multiple repairs conducted under one MWR. The failure rate of the F.C.U.s, due to leaks, is presented on attached Figure 4, in the form of a histogram.

Review of the header/stub tube/heat exchanger tube design by the NRC inspector reaffirmed the licensee's opinion of the difficulty in accomplishing effective repairs to the heat exchanger. The all-brazed design combined with the close spacing of the tubes and relative thickness of tubes and headers (0.035"/0.154-0.237"), makes localized re-brazing almost impossible. (Fix one joint and damage the braze on the adjacent tube joint.) The Maintenance Department first attempted re-brazing of the Cu-Ni materials to repair a leak. This was marginally successful along the length of the tubes, but unsuccessful at the header/stub end joints. The only successful leak repair utilized was a "temporary fix" with epoxy resins and fiber glass tape.

Leaks in large diameter cement lined pipes were temporarily repaired with "Adam's Clamps" (rubber gaskets clamped over the leak). Leaks in small diameter pipe sections were repaired with "Adam's Clamps" or by replacement with austentic stainless steel pipe. The Engineering Department indicated that the life of a "temporary fix" was 1 to 3 years.

d. Service Water System

A walk down inspection was made of the observable portions of the service water piping providing cooling water for the F.C.U.s from the 6 Service Water Pumps and their Traveling Screens to the piping penetrations outside of the Vapor Containment. The piping system is cement lined pipe up to the F.C.U. heat exchangers, where the piping is then Cu-Ni. Review of maintenance records and visual observations indicated minimal problems in the large diameter cement lined piping system outside the Vapor Containment. It was reported to the NRC inspector that there have been problems in the piping system associated with localized high velocity (design related) erosion. These problems which occurred early in service life, resulted in installation of stainless steel dutchman sections, in the piping system outside the Vapor Containment.

e. Heat Exchangers

A review was made of maintenance records for the subject heat exchangers. The purpose of the review was to obtain, if possible, a categorization of the failures in these heat exchangers associated with the Service Water cooling system. Equipment failures not related to the Service Water cooling system were not evaluated. Difficulty was encountered in analysis of the maintenance files, due to lack of explicit information on location of failures and repair technique details. Maintenance files were fortunately segregated by Fan Cooler Unit. The results of this cursory analysis by the NRC inspector are shown on attached Figure 6.

f. Meeting With The Licensee Regarding Fan Cooler Unit Heat Exchangers

On October 28, 1980, the NRC Corrosion and Metallurgy Specialist met with members of the licensee's engineering staff. The purpose of the meeting was to discuss the F.C.U. Heat Exchangers (and related parts of Service Water Cooling System) at Indian Point 2. The following information was obtained.

(1) Indian Point 2 (IP2) operation started in 1973-74, so the F.U.C.'s have seen approximately 6 1/2 years (interrupted) service.

(2) In February 1979, corporate engineering started to review the repair procedures utilized, i.e., the EPI SEAL tube plugging procedure.

(3) IP2 had requested corporate engineering to review the adequacy of the EPI SEAL procedure for temporary repairs.

(4) A temporary repair was described as a repair capable of 1-3 years satisfactory service.

(5) Corporate engineering set up a program to evaluate the EPI SEAL (epoxy) system in a steam environment.

(6) The evaluation consisted of applying a band of epoxy on a straight length of unfinned 90-10 Cu-Ni tube, curing at 80^{o}F and 120^{o}F, emersing in a steam bath for 24 hours at 212^{o}F, and attempting removal of the epoxy band by mechanical means. The results of the test indicated satisfactory adherence to the tubing. Tests were not run with fiberglass tape saturated EPI SEAL, nor were tests run on a "plugged end" technique repair.

(7) Corporate engineering reviewed a rebrazing repair technique for repair of the brazed nipple failures. This procedure would consist of cutting a "window" in the header and attempting to rebraze the nipple to header joints, then rebrazing the "window" back onto the header. Investigation indicated this repair procedure was unreliable, due to proximity of other nipples, inability to properly clean, and other difficulties meeting adequate brazing requirements.

(8) Corporate engineering indicated that the headers were all Schedule 40, standard pipe dimensions. They indicated that there were approximately 630 "U" tubes (brazed return heads) per Fan Cooler Heat Exchanger and that the manufacturer (Westinghouse) indicated that only 8 tubes could be plugged per Heat Exchanger (1.27%), without compromising the required heat transfer requirements.

(9) In December 1979, corporate engineering made an engineering decision to replace all of the Heat Exchangers (a maximum of 2 Heat Exchangers would be replaced in one regular refueling outage).

(10) A specification for new improved design Heat Exchanger has been prepared and is going through the sign off procedure. The proposed new design will utilize a rectangular cross section header with a removable cover for tube plugging purposes (A purchase order had not been placed for the revised design Heat Exchanger at the time of the meeting).

(11) Corporate engineering indicated the corrosion service behavior for other 90-10 Cu-Ni HX tubes, seeing the same service water, i.e., turbine oil coolers, lube oil coolers, inner and after condensers, hydrogen coolers, etc., has been determined to be

excellent. (It should be noted that the main surface condenser is not 90-10 Cu-Ni, but rather Silicon bronze tube sheets, Admiralty tubes, and tubes welded to the tube sheets. The service performance of the Admiralty tubes has not been excellent and currently 90-10 Cu-Ni, (AL)6X, and 904L sample tubes are being evaluated. It is reported that the 90-10 Cu-Ni tubes in the condenser "look very good".)

(12) Corporate engineering indicated that the operating procedures for the fan coolers do not include prolonged stagnant wet layup.

(13) Corporate engineering indicated that no specific failure analysis evaluations have been made on portions of failed tubing or pipe from the fan coolers.

g. Motor Cooler Hose Repair

A detailed analysis was made of the MWR 4156, which was written for the replacement of a failed motor cooler flexible hose. This MWR indicated the original hose was replaced with one fabricated of austentic stainless steel. The technique employed, retained intact the original flexible hose to 90-10 Cu-Ni pipe dissimilar metal weld. As it was believed by the licensee that the alloy composition of the original flexible hoses was austentic stainless steel, a 2" stub section on either end of the original hose has retained and prepped for welding to permit a stainless steel to stainless steel weld. The welding was performed using a stainless steel to stainless steel tungsten arc welding procedure, and austentic stainless steel steel filler metal. Review of the drawings and drawing changes for the flexible hose by the NRC inspector, indicated the original flexible hose was specified as Ni-Cu Alloy 400, then later changed to Ni-Cr-Fe Alloy 625. The weld history records confirm that the weld was made with a stainless steel to stainless steel welding procedure and with steel filler metal. The records also indicate that the finished weld was dye penetrant tested successfully.

Due to the confusion on the alloy composition of the flexible hoses the licensee conducted chemical spot identification tests on the existing flexible hoses.

A standard test with a known alloy (316) was utilized to indicate adequate activity for the reagents. The test was successful in producing the proper colorometric results. Another repeat test was run on a known sample of Ni-Cu Alloy 400 with radically different colorometric results. The NRC inspector witnessed these colorometric results. Discussions with the licensee indicated that tests were conducted on all 10 installed flexible hoses, and indicated the results positively identified the installed flexible hoses to be chromium bearing materials.

These results and other characteristics indicated the installed flexible hoses were not Alloy 400, which contains no chromium. The licensee later determined that the original flexible hoses were neither Alloy 400 or austenitic stainless steel, but rather, Ni-Cr-Fe Alloy 625.

The licensee's approved QA Program commits him to the requirements of 10 CFR 50, Appendix B. Appendix B, Criterion VIII requires that "measures shall be established for the identification and control of materials,"... and that "...these identification and control measures shall be designed to prevent the use of uncorrect or defective material, parts, and components." The inspectors review of records indicates the licensee replaced an Alloy 625 flexible hose with stainless steel flexible hose, without knowledge or engineering concurrence for the change, and then welded the stainless steel hose to Alloy 625 stub tubes, using a procedure not qualified for this dissimilar metal combination. This failure to identify and control materials is an item of noncompliance (50-247/80-19-29).

h. Unresolved Item

Based on NRC concerns expressed to the licensee during a public meeting on November 5, 1980, the licensee has committed to provide the NRC the following report by December 22, 1980.

Fan Cooling Unit Cooling Coil and Service Water Pipe Failure Analysis Report

-- providing a description of tests and inspections performed to identify the cause of failures.

-- detailing the results of the analysis of failures.

-- explaining why the proposed modified or repaired system is immune to the identified failure mechanisms or why these failure mechanisms are now tolerable.

This item (50-247/80-19-30) is unresolved.

12. Reactor Vessel Pit Flooding Analysis

a. General

The initial report of water on the Vapor Containment Floor was received by the NRC Resident Inspector on October 20, 1980. The quantity of water removed from Containment and sent to the waste holdup tank was not then known. Based on concern for the potential consequences of submergence of the Reactor Vessel, it was determined to be necessary to quantify the maximum flooding elevation of the Reactor Vessel Pit.

b. References

The following documents were reviewed:

(1) Indian Point Station, Unit 2, SOP 5.1.2, Rev. 0, Radioactive Liquid Waste Discharge and Transfer Operator

(2) Indian Point Station Support Facilities, Unit No. 1, 0-37.5, Liquid Waste Evaporators, No. 12 and No. 13

(3) Unit 2, Containment Water inventory Calculator Sheet

(4) Waste Collection Tank Level Transmitter Calibration MWR's

(5) Nuclear Area - Log Sheets (Shutdown Conditions)

(6) Waste Collection Tanks Height vs. Volume Sheets

(7) Unit 2, Water Capacity above Reactor Pit, Volume calculation

(8) Work Sheet Water Inventory 10/17 to 10/20

(9) Unit 2, Waste Holdup Tank - Volume curve

(10) Inspector's Preliminary Calibration Sheet

(11) Con Ed Drawing No. A 188852-2

(12) Con Ed Drawing No. A 188851-9

(13) Graver Tank Drawing No. L 18438-6

c. Preliminary Licensee Estimates of Reactor Vessel Pit Flooding

The method used to control liquid radioactive waste at the Indian Point, Unit 2, utilizes the Unit 1 Support Facility's waste evaporation and storage tanks. Following discovery of water on the Vapor Containment floor and the restart of the two Vapor Containment Sump Pumps, all Containment Liquid Effluent was transferred to the Unit 2 waste holdup tank, where, upon reaching a predetermined level, the waste was then transferred to the Unit 1 facility.

The inspector's initial inquiry as to the volume of liquid pumped from the containment yielded an estimate by the licensee of 40,000 to 43,000 gallons. The inspector further requested data on the required volume of liquid necessary to touch the bottom of the Reactor Vessel. Initial calculations performed by the licensee estimated 59,928 gals. of liquid in the Reactor Vessel Pit would be required to bring the water level in contact with the Vessel. Based on the preliminary estimate of 43,000 gals. transferred and approximately 60,000 gals. needed to contact vessel, the licensee determined that water did not touch the Vessel. The inspector requested data to confirm these initial water estimates.

The entrance points of liquid waste into the Reactor Vessel Pit are limited to two defined areas; the Incore Instrument Tube entrance and a locked grating and hatch entrance leading to the Reactor Vessel viewing platform. Both of these areas have a 6 inch curb or lip that should prevent flow from the Vapor Containment Floor, until the floor water level exceeded 6 inches. The amount of water on the Vapor Containment Floor, needed to overflow into the Reactor Vessel Pit, was tentatively estimated by the licensee to be 41,646 gals. Thus, with a preliminary estimate of liquid waste discharges and the water on the Containment Floor needed to overflow into the pit, it was determined by the licensee that only 1354 gallons (43,000-41,646 = 1354) flowed into the pit.

d. <u>Initial N.R.C. Observations of Reactor Vessel Pit</u>

On completion of review of the licensee's preliminary water inventory calculations, which on October 21, 1980, appeared to support the assumption that Reactor Vessel was not wetted, the NRC Resident Inspector made direct observations of the Reactor Vessel Pit area. The following items were observed on entry at 1659 hours on 10/21/80.

1) At the foot of the 46 foot level in the Vapor Containment building, small pools of water (1/4 inch to 1/2 inch in depth) were observed.

2) Upon reaching the Reactor Vessel Pit intermediate platform, the permanent lighting was found to be inoperable.

3) By use of a portable light, the following areas were observed and found to have white, salt-like precipitate covering.

    a) The Reactor Vessel Mirror Insulation at the "orange peel" seams.

    b) The Reactor Ventilation Duct encircling the Vessel.

4) No water was observed on top of the ventilation duct.

5) In the Reactor Vessel Pit, the licensee was removing one of the Pit Sump Pumps. The electrical connections to the pump had been previously removed and no judgement as to quality of original electrical hook-up could be made.

Based on observations, but not supported by either the licensee's or the inspector's preliminary water inventory calculations, the inspector concluded that the Reactor Vessel had been wetted.

e) Additional Licensee Estimates of Pit Flooding

On October 22, 1980, an estimate of about 100,000 gals of liquid removed from the Containment was announced. The licensee had determined the earlier estimates to be in error, in that they did not take into account the removal of liquid from the Unit 1 collection tanks during waste processing.

The licensee's new estimates were based on the following calculations and assumptions; corrected total transfer to Unit No. 1 Storage & Processing Tanks (129,110 gallons), minus Unit 1 and Unit 2 normal outside containment leakage (20,042 gallons), minus continued leakage into containment during pumpout (21,600 gallons). This new computed volume pumped from the vapor containment was 129,110 - 41,642 = 87,468. Additional discussions and using more conservative figures for system leakage brought totals to approximately 98,264 gallons waste liquid removed from Containment.

Based on the original estimated floor capacity of 41,646, the amount of liquid in the Reactor Vessel pit was now estimated at 98,264 - 41,646 = 56,618 gallons. This amount would not wet the Reactor Vessel, assuming the licensee's estimate of 59,928 gallons to just touch the Vessel was correct.

f. NRC Reactor Vessel Pit Water Level Observations Curve

An NRC Reactor Vessel Pit Water Level observation curve (Figure 1) was developed by reviewing and evaluating various logs and testimony of individuals with first hand knowledge of the Reactor Vessel Pit water level, observed on their various entries into the Vapor Containment. The best estimate water levels were then plotted against times gleaned from Vapor Containment entry logs, operator logs and eyewitness accounts of the activities of the water level observing individuals. The resulting plot supports the licensee's estimate of maximum potential Reactor Vessel submergence and shows only one peak without level cycling.

g. Unresolved Items

At the completion of the onsite investigation, the licensee had not resolved the discrepancies between water level observations and volume calculations. Recent survey results strongly suggest that additional level indication should have indicated the collecting water level was about to flow into the Reactor Vessel Pit. Since no one reportedly observed this indication, the operability of the level detector, or the path river water utilized to enter the Reactor Vessel Pit, remains in question. To resolve these matters, the licensee has committed to providing NRC the following reports by 12/22/80.

(1) Reactor Vessel Pit Water Transport Path Report

-- explaining how water entered the reactor vessel pit without indication of this condition.

This item (50-247/80-19-31) is unresolved.

(2) Vapor Containment Survey Evaluation Report

-- providing surveyor results of floor sump and equipment elevations;

-- listing equipment and surfaces wetted during flooding event;

-- listing equipment potentially floodable had the condition not been accidentally detected;

-- discussing the impact of the actual wetting and planned corrective actions;

-- discussing the potential impact of the flooding had it continued; and

-- discussing the impact on the equipment and surfaces wetted of the residual levels of contaminants following planned corrective action completion.

This item (50-247/80-19-32) is unresolved.

(3) Recirculation Sump Activity Level Evaluation Report

-- providing an explanation, including the most probable source, for the observed activity of the recirculation sump water, following the flooding event.

This item (50-247/80-19-33) is unresolved.

13. Previous History of Containment Flooding

a. General

The inspector reviewed AEC, NRC and licensee documents of previously reported Containment flooding events, that lead to water flow into the Reactor Cavity Pit.

The review was conducted to identify events which had the potential for wetting the Reactor Vessel and to gather information relative to the events.

b. References:

-- Event 1

(1) WEDCO Containment Integrated Leak Rate Report

(2) Memorandum F. Noon to W. Monti, 1PP-80-556, dated November 14, 1980

-- Event 2

(1) Consolidated Edison Co Report to AEC, dated 11/30/73

(2) Notification of Occurrence, dated 11/14/73

(3) IE Report 50-247/73-20

(4) Report to AEC, dated 1/14/74

(5) Memorandum J. Makepeace to J. O'Toole, dated 11/19/73

-- Event 3

(1) Reportable Occurrence Report 77-2-14

(2) IE Report 50-247/77-24

(3) Memorandum J. Dutch to J. Makepeace, dated 8/12/77

(4) Senior Watch Supervisor Log Excerpts, 7/1/77 to 7/5/77

c. Event 1 - March 7, 1971

On March 4, 1971, the Vapor Containment was subjected to a preoperational "Containment Integrated Leak Rate Test", which required the internal pressurization of the containment structure to a pressure of 47 psig.

Three days into the test, it was determined by the licensee's test coordinator, that liquid was collecting in the containment structure. Subsequent investigation found that pressurized temporary Service Water piping to a Fan Motor Cooler had failed.

Service Water (river water) was found on the Vapor Containment Floor, 4-6 inches, and in the Reactor Vessel Pit to a depth of approximately 13 feet. Based on a Reactor Vessel Pit Floor elevation of 18 feet, the additional flooding depth estimate of 13 feet, and a Reactor Vessel Lower Head bottom elevation of 34 feet, the Vessel should not have wetted (18 + 13 < 34).

During the period of potential Reactor Vessel wetting, the Vessel was at ambient temperature and had not yet been fueled.

d. <u>Event 2 - November 13, 1973</u>

On November 13, 1973, with the Reactor at 7 percent power and 547^{o}F, a crack developed in an 18 inch feedwater line to No. 22 Steam Generator inside the Containment. Condensate (demineralized water) collected on the Vapor Containment Floor and in the Reactor Vessel Pit; the latter, to a measured depth of 56 inches. The Incore Instrument Conduits were subsequently cleaned. The Reactor Vessel Lower Head was not contacted by cold water during this event.

e. <u>Event 3 - July 2, 1977</u>

On July 2, 1977, with the Reactor at 2 percent power and 547^{o}F, Control Room alarms and instrumentation indicated a failure of the No. 23 Reactor Coolant Pump seal package. Failure of the seal package enabled Reactor Primary Coolant to flow into the Vapor Containment and Reactor Vessel Pit. The licensee's report to NRC indicates the total loss of coolant to the Containment to be approximately 90,000 gallons. No documentation or report of observed water levels in the Reactor Vessel Pit following the event have been identified. Recent licensee calculations of the volume of water required to collect in the Vapor Containment to just touch the bottom of the Reactor Vessel Lower Head (94,000 to 97,000 gallons), would indicate that the spilled volume of hot demineralized water was probably not sufficient to touch the Reactor Vessel.

f. <u>Conclusion</u>

Of the three events identified as having potential for Reactor Vessel wetting, only the November 13, 1973, Feedwater Line Crack event can be ruled out with hard evidence as not wetting the Reactor Vessel.

The March 7, 1971, Service Water flooding event estimate of Reactor Vessel Pit flooding depth is poorly supported by documentation, and approaches contact of the Vessel within 3 feet. Based on the temperature of the Reactor Vessel at the time of the event, the material of Reactor Vessel construction and the characteristics of the Reactor Vessel painted surface, no problem with the Reactor Vessel would develop from this event had wetting occurred.

The July 2, 1977, Pump Seal Failure flooding event estimate of flooding volume closely approaches the required volume to contact the Reactor Vessel. Based on the initial 547^{o}F temperature of the flooding water and the fact that the water was dimineralized, no excessive Reactor Vessel stress or corrosion problems are predicted.

14. Reactor Vessel Integrity Following Partial Immersion

a. General

As previously described, flooding of the Reactor Vessel (RV) Pit would cause partial immersion of the RV in water. Chloride ion swipe tests, described elsewhere in this report, and observations of Reactor Vessel Pit water level indicate that about 9 feet of the RV was immersed in River Water. This immersion produced thermal gradients that increased Reactor Vessel outside diameter surface tensile stresses.

Analyses of the effects of the unusual thermal gradients were made by the licensee, Westinghouse Electric Corp, and Nuclear Energy Services, Inc.

It was reported by Westinghouse that the efficiency of the mirror insulation is sufficient to maintain a condition of essentially no temperature drop accross the wall of the Reactor Vessel, during normal operation. Immersion would produce a thermal gradient that would add to operating pressurization stresses.

b. Stress Analysis

Analyses by Westinghouse indicated that immersion to the depth reported would result in three areas of concern. These are increased stresses in the lower head to cylindrical section transition, increased stresses at the locations of the lower head instrumentation nozzle penetrations, and permanent distortion of the tongue and groove joint into which the core barrel fits. In 1973, immersion stress and fracture toughness calculations were made (by W. H. Bamford, "Fracture Analyses - External Thermal Shock") assuming a deeper immersion in 130^{o}F water and considering the calculated loss of toughness (from irradiation) at the end-of-design-life. These calculations indicated that a critical flaw would have to be approximately 20% of the wall thickness.

The current Westinghouse fatique usage calculations, dated November 4, 1980, assumes 100^{o}F water in contact with the RV. The ambient river water temperature at the time of the incident was approximately 65^{o}F. The water from the relatively slow leaks had to flow over and remain in contact with 112-120^{o}F structural material. The water temperature would rise asymptotically to the containment temperature. The Westinghouse fatique usage calculations did not elevate the Reactor Vessel outer wall temperature above that of the 100°F water. (A realistic boiling situation would only cool the RV outer wall to approximately 200-220°F, due to boiling film coefficients.) Finite element methods were used to determine temperature distributions, thermal stresses, pressure stresses and associated displacements. The stresses were categorized per NB-3223. Computer program WECEVAL (3) was used to linearize the stress distributions and determine the maximum range of primary and secondary stress intensities.

The calculations were made for 5 water level positions and the stress intensities were compared to ASME critiera.

The Westinghouse calculations show a maximum fatique usage factor per immersion of 0.0062 in the lower head/shell transition (a factor of 1.00 is required for calculated fatique failure). The nozzle penetration area fatigue usage factor per immersion is lower. The Westinghouse calculations show the displacement or rotation of the tongue and groove core barrel support to be less than the allowable tolerance.

A Westinghouse fracture analysis was made for the outside diameter surface temperature change, from normal operating wall temperatures to immersion temperatures, for transients from 50 seconds to 1500 seconds. Stress intensity factors (KI) were calculated in accordance with Appendix A of Section XI, Division 1 of the ASME Boiler and Pressure Vessel Code. The assumed surface flaw was a semi-elliptical surface flaw with a length to diameter ratio of 6, with longitudinal (worst case) orientation. The calculations used a conservative worst case bulk water temperature of 100°F and a heat transfer coefficient of 2000 BTU/hr-ft^2-°F, to determine the temperature of the outer wall. The analysis results in a critical flaw size of 1.05 inches for the bottom head and 1.68 inches for the lower shell.

Westinghouse also performed fracture analysis for the Incore Instrumentation tube penetration region. The analysis utilized a 100°F temperature for the outer wall of the vessel. The weld joint for the penetration is on the inside diameter of the vessel, which on the worst case is at 455°F, which keeps the metal (RV Steel Head) at the upper shelf of the fracture toughness curve. The maximum calculated stress intensity factor is an order of magnitude less than allowable. The calculation indicates there is no possibility for crack propagation associated with the nozzle penetration. This conclusion is in accordance with ASME Section XI, Appendix A analysis methods.

The analysis conducted by Nuclear Energy Services, Inc. was entitled "Thermal Transient Safety Evaluation of the Indian Point 2 Reactor Pressure Vessel Bottom Head During Containment Building Flooding". The NES evaluation utilized the LION4 heat transfer computer code to calculate the thermal response of the RV lower head to immersion in water. This analysis permitted lowering of the outside diameter of the RV to 212°F. A 10 GPM leak rate was postulated to provide the rate at which the RV was submerged. The ANSYS finite-element computer code was utilized for stress analysis. The primary and secondary stresses from pressure loading are within requirements of NB-3221.2 and NB-3221.3. The maximum secondary stresses resulting from axial and radial thermal gradients are within the requirements of NB-3213.13(a). The calculated equivalent fatique usage factor per immersion is 0.0006 per cycle of immersion.

A review of the aforementioned analysis by the NRC inspector indicates that the immersion of the RV did not consitute a significant structural transient and had negligible effect on the life of vessel.

c. Unresolved Items

Based on NRC concerns expressed to the licensee for the acceptability of the assumptions used in calculating Reactor Vessel stresses and in defending his position that the Reactor Vessel had not been damaged, the licensee has committed to provide the following reports by 12/22/80:

Incore Instrument Stub Tube to Reactor Vessel Weld Failure Consequence Report

-- providing the results of flow rate calculations from an incore instrument thimble hole in the reactor vessel, should the tube to vessel weld experience a 360° failure;

-- assuming conditions with and without stub tube ejection.

This item (50-247/80-19-34) is unresolved.

Reactor Vessel Stress Analysis Report

-- assuming submergence in 60°F service water while at full power;

-- providing rational for continued operations.

This item (50-247/80-19-35) is unresolved.

15. Containment Paint and Insulation

The containment floor and wall liner are covered with a protective paint coating, over their entire surface. The wall liner is additionally protected by insulation on its inside surface. This insulation is then covered with a metal canning, which is caulked between the wall sections and where the floor meets the wall. During various containment tours, the inspectors noted that the paint was damaged and peeling in many areas and that the caulking used for the metal canning was cracked and peeling, also. The licensee stated that both would be restored to their origional condition.

This item is unresolved and is designated as Item No. (50-147/80-19-36).

16. Mirror Insulation

a. Discussion

The NRC Inspector reviewed the insulation drawings with a representative of Diamond Specialty Company (B&W). The drawings reviewed were as follows:

MIC-369-001C
-003C
-023C
-026C
-027C

The drawings indicated reflective metallic materials versus bulk insulation were utilized. The insulation consisted of panels, fabricated as an American Iron and Steel Institute 304 jacket with a 3003 Aluminum multi-layered mirror lining, and stainless steel wool insulation, between the instrumentation nozzles and mirror insulation jackets. The insulation was ordered from Diamond Specialty, as a Westinghouse Subcontract, and installed to WAPD 54-F70611B.

Since expansion and escape of the air trapped under the insulation must be allowed in the design of the insulation system, the insulation is not water tight; and therefore, must be assumed to have allowed river water on the inside diameter of the stainless steel jacket. Exposure of the mirrored surface to an active corrodant might have adverse effects on the insulation capabilities. Visual inspection of the insulation by the NRC inspector did not reveal any indication of damage to the insulation by the immersion in diluted river water.

b. Unresolved Items

The licensee has committed to provide to the NRC by December 22, 1980, a report which will:

-- describe the test procedures and objectives of a program to demonstrate that the mirror insulation will perform in accordance with specifications.

-- justify that the Reactor Vessel can safely operate in accordance with technical specifications with degraded mirror insulation.

This item is considered unresolved and is designated Item No. (50-247/80-19-37).

17. Steam Generator Blowdown Line Leaks and Supports

a. References:

(1) Quality Control Inspection Reports (Q.C.I.R.s) 80-2-42, 42A, 42B

(2) MWR - 2937 - Steam Generator No. 21

(3) Dwg 9321-F-2558-3

(4) MWR 1715 and 1719

(5) I.P. Station Maintenance Procedure - Removal of No. 21 Steam Generator Shell Drain Line (SNSC Approved 6/9/80)

(6) Safety Evaluations, 10 CFR 50.59

b. Latest Leak

On October 18, 1980, during a Vapor Containment entry, an operator identified a leak on the blowdown piping from No. 21 Steam Generator.

The 2 inch line had developed a leak at an inboard 45^{o} weld which caused a visible plume inside the Missile Shield. The leak was temporarily repaired with an overlay of weld material. An operations pressure test was conducted at the conclusion of the repairs. During subsequent Quality Control Inspections of the repairs, the licensee identified on Q.C.I.R.s, three missing pipe hangers. Discussion with corporate field Quality Assurance Engineers indicated that the three hangers, identified by the Q.C.I.R.s, were to be replaced.

c. Previous Problems

On June 7, 1980, a shell drain line from No. 21 Steam Generator failed at the Steam Generator/pipe interface. This line shares a common discharge header with the No. 21 Steam Generator Blowdown Line, which developed a leak on 10/18/80. Repairs of the drain line involved welding a new pipe stub on the Steam Generator, removing an isolation valve, and plugging the two open pipes, thus eliminating the shell drain. The licensee attributed the line failure to water hammer from the operator of the solenoid operated isolation valve. The licensee had further identified one hanger and one snubber which had failed. The NRC Resident Inspector made a tour of the area on 6/9/80, and verified the licensee documented observation.

d. Unresolved Items

(1) The inspector requested the licensee to perform the following items to assure the blowdown piping system is properly supported:

(a) Review licensee's response to Inspection and Enforcement Bulletin 79-14 and the results of the licensee's surveys as to the ability of the present hangers to seismically support blowdown system piping;

(b) Verify by walking the lines, that the present hangers on the blowdown piping are located in accordance with as-built plans;

(c) Identify and resolve discrepancies in accordance with Quality Assurance Procedures;

(d) Describe analysis performed that justified elimination of a number of hangers on the blowdown system; and,

(e) Describe hydraulic shock effects on the blowdown piping resulting from opening and closing the solenoid operated isolation valves.

This item (50-247/80-19-38) is unresolved pending the completion of the licensees investigation and review of resulting documentation by the NRC.

(2) Based on NRC concerns expressed to the licensee at a public meeting on November 5, 1980, the licensee has committed to provide the NRC the following report by December 22, 1980.

Steam Generator Blowdown Line Failure Analysis Report

-- providing a description of tests and inspections performed to identify the cause of failures.

-- detailing the results of the analysis of failures.

-- explaining why the proposed modified or repaired system is immune to the identified failure mechanisms or why these failure mechanisms are now tolerable.

This item (50-247/80-19-39) is unresolved.

18. Corrosive Effects of Immersion in River Water

a. General

The leakage of the Fan Cooler Units and Steam Generator Blowdown Line into the recirculation sump, Vapor Containment sump and finally the Reactor Vessel Pit, caused partial immersion of the Reactor Vessel, immersion of the Reactor Vessel Incore Instrumentation nozzles and conduits, immersion of a portion of the Residual Heat Removal piping, and immersion of a portion of the Reactor Vessel Mirror Insulation.

The materials exposed to the diluted river water corrodant were the SA302, Grade B (Manganese-molybdenum low alloy steel) weld fabricated Lower Reactor Vessel Head, Alloy 600 (Nickel-chromium-iron) Incore Instrumentation nozzles with a 316 stainless steel nozzle safe-end, 316 stainless steel Incore Instrumentation Conduit and Conduit couplings, and stainless steel jacketed aluminum Reactor Vessel Mirror Insulation.

The corrosive effect of exposure of metallic parts to diluted Hudson River water was studied by the NRC Corrosion and Metallurgy Specialist and determined to be a function of the following:

1. Alloy composition

2. State of surface stresses during exposure

3. Corrodant and concentrating mechanisms

4. Metal temperature

5. Time of exposure

b. Material of Construction

The NRC Specialist reviewed the Reactor Vessel fabrication sequence obtained through Westinghouse Corporation. The Reactor Vessel was fabricated by submerged arc welding. The lower head consists of a lower dome and orange peel (torus) segments. The contoured sections are hot formed above the lower critical temperature, then quenched and tempererd to produce the desired toughness and mechanical properties. The bottom dome is surfaced (weld clad) on the inner diameter with austenitic stainless steel, then given a subcritical interstage post weld heat treatment (P.W.H.T.). The orange peel sections are joined together by submerged arc welding, given a subcritical interstage P.W.H.T., then surfaced on the inner diameter (weld clad) with austenitic stainless steel, and then given another P.W.H.T. The bottom dome is then joined to the orange peel sections and the joint surfaced (weld clad) with austenitic stainless steel, and then given an interstage P.W.H.T. The holes and weld joint geometries are then machined for the Incore Instrumentation nozzles. The exposed steel on the nozzle weld joint geometry is manually weld surfaced (clad) with a Ni-Cr-Fe (Inconel type) filler metal, as is a pad approximately 3 1/2" in diameter, by approximately 3/8 inch thick deposited around the holes on the outside diameter of the head. Following this welding is another interstage P.W.H.T. The Reactor Vessel Lower Head is then joined to the lower Vessel assembly by submerged arc welding, the weld joint back surfaced (clad), and given another interstage P.W.H.T. Following joining of the lower Vessel assembly to the upper Vessel assembly (closure seam), the entire vessel is then given a complete P.W.H.T.

The Ni-Cr-Fe Alloy 600 nozzles are then inserted in the Incore Instrument penetration holes in the Reactor Vessel Lower Head. The diametral clearance of the nozzles and penetration holes is 0.004" maximum. The nozzles are then welded into the Head using Ni-Cr-Fe (Inconel type) filler metal. The weld metal is deposited on the surfaced (clad) weld joint geometry, thus eliminating a weld HAZ on the RV head.

The complete sequence of intermediate and final P.W.H.T. of the Reactor Vessel pressure boundary welds, should render the lower Head and porton of the lower Vessel Assembly, which was exposed to the corrodant, essentially free of weld induced residual and other fabricating stresses. Following hydrostatic testing of Reactor Vessel and magnetic particle testing (MT) of the entire outside diameter exposed surface, the vessel is painted with a 2-4 mil single coat of Placite 888 (an aluminum rich silicone base high temperature paint). The painting system meets the requirements of Westinghouse WCAP 7153. The painting sequence accounts for the observation of paint droplets on the Instrumentation nozzles.

The austenitic stainless steel weldments (Incore Instrument Conduit to Nozzle safe end socket fillet welds and Conduit to Conduit socket fillet coupling welds) and the austenitic stainless steel safe end to Nozzle weldments did not require or receive a P.W.H.T. These weldments could retain yield strength level residual welding stresses. The weld area including the weld HAZ must be assumed to have surface tensile stresses.

c. Material Susceptability to Corrosion

The corrodant is Hudson River Service water, diluted with steam from a Steam Generator Blowdown Line leak. The maximum concentration of Chlorides was believed to be approximately 3400 ppm, NaCl, as analyzed by the licensee's Chemistry Lab from water taken from the Reactor Vessel Pit. It is a reasonable assumption that this water was in contact with the heated surfaces of the Reactor Vessel, radiation heated

Reactor Vessel Mirror Insulation and conduction heated Incore Instrument Nozzles. The heated surfaces could provide a concentrating mechanism for the chlorides. The unheated surfaces would not provide a concentrating mechanism for the chlorides.

The metal temperature of the heated parts exposed to the corrodant may be assumed to be approximately that of the boiling point of water. The time of exposure from all existing data appears to be less than 51 hours.

The Reactor Vessel Head material and Ni-Cr-Fe Alloy 600 Nozzle material are known to be resistant to stress corrosion cracking in the presence of chlorides. The austenitic stainless steel weld area of the heated Ni-Cr-Fe Nozzle to 316 safe end and safe end to conduit welds are less resistant to stress corrosion cracking, as they contain the necessary prerequisites of a susceptible material, possible surface residual tensile stresses, a temperature above 150°F and the presence of chlorides. These areas are considered to be the most susceptible to corrosive attack during the immersion.

d. Recommendations and Results

The NRC Corrosion and Metallurgy Specialist indicated that all areas which could have been adversely affected by the corrodant, should be subjected to non-destructive examination to detect the presence of incipient cracking. The licensee conducted magnetic particle testing of all weld seams on the Reactor Vessel Lower Head and dye penetrant testing of Incore Instrument Nozzle safe end welds, Nozzle to Conduit socket fillet welds, conduit coupling socket fillet welds, and the entire length of Conduit immersed in the corrodant. No indications were reported by the licensee.

The NRC conducted a third party verification inspection of the Reactor Vessel welds and a statistical inspection of the austenitic stainless steel welds. The third party inspection also reported no indications.

The licensee and third party NDE results indicate that the immersion of the vessel in the corrodant resulted in no corrosion damage to the exposed parts.

19. Chloride Contamination Survey

a. Chloride Swipe Test

The swipe test for chlorides is routinely used to determine levels on "Chloride free" and "chloride contaminated" surfaces. A standard chloride level for a "chloride free" surface is <0.08 mg/dm^2. The test consists of taking a clean (gauze square) swathe cloth and wiping an area approximately 10 cm x 10 cm (1 dm^2), boiling the swathe to transfer the retained chlorides to solution, then acidifying and titrating with Hg $(NO_3)_2$ to determine chlorides (ASTM:D512 Chloride Technique). Due to slight technique variations in the exact determination of the area and variable applied pressure used to achieve the wiping of the surface, the test cannot be considered to produce absolute quantitative results.

In order to verify the test, the licensee conducted a referee test utilizing a Dionex Model 14 ion chromatograph. The licensee indicated that the ion chromatography verified that their swipe test procedure accurately reported titrated chlorides and that on the specific swipe test, verified that the chlorides came from a water sample qualitatively and semi-quantitatively the same as the river water sample obtained on 10/22/80. The ion chromatography procedure followed for chloride analysis is not a standard ASTM procedure, but is currently being reviewed by committee D19 as a proposed analysis method. The referee test is basically a verification that the Hg $(NO_3)_2$ titration technique for the swipe test is properly reporting Chloride Ion concentration and characterizing the solutions analyzed as river water.

b. NRC Observations

The NRC inspector witnessed a complete laboratory "boildown" and a complete "dip" swipe test with a referee blank sample. The dip test was accomplished by wetting the inside surface of a stainless steel tank for the ultrasonic cleaner with River water, allowing it to dry, and wiping an approximately 100 cm^2 area with a swathe. The "boildown" test consisted of taking 50 ml of the 1 meter deep weekly composite 10/22/80 River water sample and evaporating to complete dryness in a 500 ml beaker. The surface area wetted with 50 ml of water in a 500 ml beaker was measured and estimated to be 113 cm^2. Upon completion of evaporation and cooling, the beaker showed a relatively heavy layer of dried salts. The contaminated surface of the beaker (approximately 113 cm^2) was wiped with a swathe cloth using the standard swipe test procedure. The results were 113 mg by titration methods. A licensee calculation of the chlorides expected, based on 4600 ppm NaCl in the River water, was 139 mg (in 50 ml).

c. Licensee Findings

The initial series of swipe tests were conducted from 10/20/80 to 10/24/80. The swipe test results for chlorides conducted on the ambient temperature stainless steel conduit lines varied between 0.1 and 1.0 mg/dm^2, which is on the order of that determined by the laboratory (ultrasonic cleaner tank) ambient temperature dip test which was 0.2 gm/dm^2. The swipe tests conducted on the Reactor Vessel Head yielded results which varied from 20 to 80 mg/dm^2, with one probably bad result of 117. These values are indicative of boildown concentration mechanisms and are similar to that obtained in the laboratory 50 ml boildown tests. The results of swipe tests taken on the outside diameter of the mirror insulation are greater than those for the unheated conduit (between 1.2 and 1.7 mg/dm^2) but less than the chlorides obtained from the hotter surfaces on the Reactor Vessel Head.

A second series of swipe tests were run on the Reactor Vessel from 10/29/80 to 11/3/80. The 10/29/80 swipe tests were run at 4 radial locations on the Reactor Vessel Head, essentially every foot of elevation, from the bottom of the Reactor Vessel Head to an elevation of 7 feet. On 11/3/80, an additional series of Reactor Vessel Swipe tests were run from an elevation of 7 feet to 10 feet, above the bottom elevation of the Reactor Vessel Lower Head. The swipe test results from the one foot to 7 foot elevation vary from 10.2 - 72 mg/dm^2.

The 7 foot to 10 foot swipe test series statistically show lower values (6.0 - 14.5 mg/dm^2). The swipes at one radial location indicate the most probable high water level with the following values:

Est. Relative Bldg. El.	Height Above RV Bottom	Cl^- (Mg/dm^2)
	7'10"	14.5
42'	8'0"	11.5
	8'4"	12.5
	8'8"	0.36
43'	9'0"	0.68
	9'6"	0.36
44'	10'0"	0.23

The water level indicated by these chloride swipes was most probably between the 8 foot 4 inches and 8 foot 8 inches height on the Reactor Vessel, which roughly corresponds to 42 foot 4 inches to 42 foot 9 inches, in building elevation. The values below the 8 foot 4 inch level on the Reactor Vessel represent concentration caused by the heated surface. The values above the 8 foot 4 inch level represent chloride carryover from the boiling regime.

d. Unresolved Item

Based on NRC concerns expressed to the licensee at a public meeting on November 5, 1980, the licensee has committed to provide the following report to NRC by December 22, 1980.

Reactor Vessel Paint Chloride Retention Report

-- describing the results of tests, inspections or analysis that establish the probable Chloride residue retained by the reactor vessel paint.

-- discussing the impact of the residue on continued operations.

This item (50-247/80-19-40) is unresolved.

20. Non-Destructive Examination of Reactor Vessel Lower Head, Incore Instrumentation Nozzles and Conduit, and Residual Heat Removal Piping

a. NRC Observations

The Reactor Vessel (RV) Lower Head was visually examined by the NRC Corrosion and Metallurgy Specialist shortly after removal of the lower head mirror insulation. Examination was made with the unaided eye with marginal lighting and a flashlight. The RV Lower Head is painted with a heavily layered beige colored paint. It appears that the paint was applied after installation of the instrument penetration nozzles, as a considerable amount of paint drops were observed on the nozzles. No evidence of red rust ($Fe(OH)_3$) was noted, even in areas where it appears there is little or no beige paint. No evidence of heavy salt encrustation was noted on the head; however, there appeared to be a translucent haze on the painted head.

Portions of the stainless steel wool type insulation continued to adhere to the nozzle/head intersections. This material did appear to have the color of red rust.

No evidence of localized or general corrosion attack on the head, nozzles or conduit was noted. No evidence of any linear cracklike indications were noted in suspected areas of high surface tension stresses, i.e., weld HAZ.

No pigmented corrosion products were noted on the Ni-Cr-Fe Alloy 600, nozzle, nozzle to safe weld, 316 safe end, safe end to conduit socket fillet weld, 316 conduit, or conduit to coupling welds. No evidence of heavy or light salt encrustations were observed on the aforementioned parts.

b. Licensee Examinations - Incore Instrument Nozzles

The licensee conducted a series of dye penetrant (PT) examinations, of the non-ferrous reactor welded joints exposed to the diluted river water. These joints consisted of the Ni-Cr-Fe Alloy 600 instrumentation nozzle to austenitic stainless steel safe end welds, nozzle safe end to austenitic stainless steel conduit socket fillet welds, and conduit coupling welds. The first results were reported in QCIR 80-2-44, dated 10/24/80. Due to the residual heat in the RV, a high temperature (125-150^{o}F) PT technique was required for the nozzles. In addition to the 21 nozzle safe end and socket welds examined, 32 20-25" long sections of conduit not containing welds were examined. No relevant indications were noted.

On 10/26/80, the licensee attempted to conduct PT examinations of the complete nozzle extension. This PT examination utilized a PT cleaner as a pre-cleaner, but resulted in a large number of non-relevant indications caused by the paint drops remaining on the nozzles. Licensee representatives indicated that mechanical cleaning would be necessary if these areas of the nozzles were to be given a PT examination. The NRC inspector concurred that minor cleanup with emery paper should be utilized, where required. The results of the PT over the paint drops were disregarded due to the prevelance of non-relevant indications; however no crack like indications were noted. The NRC inspector witnessed a small sample of the licensee's dye penetrant (PT) examinations and reviewed results for a complete (10/25/80) reexamination of all nozzle to safe end welds and safe end to conduit socket fillet welds. No relevant indications were reported.

c. Licensee Examination - Reactor Vessel

On 10/29/80 and 11/1/80, the licensee conducted a 100 percent magnetic particle (MT) inspection examination of the dome to torus, torus longitudinal, torus to lower shell and 16 inches of the two lower shell longitudinal welds. The NRC inspector reviewed the procedure performed on unpainted and painted test assemblies, including review of the photographs showing reproducible powder indications. The MT examinations showed no indications.

d. Licensee Examination - Incore Instrument Conduits

The licensee also conducted a 100 percent PT examination of the portion of the 58 conduit lines exposed to the flooding water. No indications were reported.

e. Licensee Examination - Residual Heat Removal (RHR) Piping

A portion of the RHR stainless steel piping which extends to the Vapor Containment Sump was exposed to ambient temperature diluted river water. The RHR piping was hydro-statically tested at 100 psig for 60 minutes and visually examined by the licensee for leaks on the outside diameter of the pipe at the weld joints. No leaks were reported.

The licensee radiographically examined weld numbers 57-3 to 57-6. No indication of chloride ion cracking was identified. Engineering disposition of identified welding and manufacturing defects indicated these defects were not related to the exposure to river water and were considered to be acceptable.

f. Licensee Examination - Procedures & Personnel

The licensee procedures and qualifications of NDE personnel were reviewed by the NRC inspector. No problems were identified.

21. Independent Nondestructive Examination of the Indian Point Unit 2 Reactor Vessel Lower Head Welds, Stub Tube Welds and Conduit Welds

a. General

Following the determination that the Reactor Vessel Lower Head and Incore Instrument Conduits were submerged in Service Water, while at normal operating temperature, the licensee performed nondestructive examinations of the Reactor Vessel Lower Head welds, Stub Tube welds and Incore Instrument Conduits.

The NRC contracted Parameter Incorporated of Milwaukee, Wisconsin to provide an independent nondestructive examination of the above mentioned welds and conduits to verify the licensee's examination results.

b. Work Scope

The work scope was as follows:

(1) Provide a technical evaluation of the suitability of performing a magnetic particle examination of the reactor vessel lower head, without removal of the protective coating.

(2) Perform a procedure qualification to demonstrate that the magnetic particle examination methodology to be used is capable of detecting flaws in the licensee's coated calibration standard.

(3) Supply the necessary qualified (SNT-TC-1A) personnel and equipment, perform magnetic particle inspections using the AC yoke method of the following IP-2 reactor vessel welds:

(a) Circumferential Lower Head to Shell weld.

(b) Lower Head meridional welds (orange peel).

(c) Lower Head circumferential weld (dollar piece).

(d) One foot of the longitudinal Shell welds, intersecting the circumferential Shell to Lower Head weld.

(4) Supply the necessary qualified (SNT-TC-1A) personnel and equipment, perform liquid penetrant inspection of the following:

(a) 25 percent of the instrument nozzle to safe-end and safe-end to instrument socket welds. Include in the sample those nozzles which are observed to have longitudinal marks.

(b) 10 percent of the conduit welds which could have been exposed to the leaking service water.

c. <u>Personnel</u>

The above work was done by six Peabody Testing Services personnel under the direction of an NRC N.D.E. Specialist.

The examination personnel were qualified and certified as follows:

<u>Magnetic Particle Examination</u>

-- Two Level III individuals

-- Four Level II individuals

<u>Liquid Penetrant Examination</u>

-- Two Level III individuals

-- Two Level II individuals

-- One Level I individual

d. <u>Technique</u>

Magnetic particle examinations were done using Magnaflux Corporation model Y-6 AC yokes, serial number HAR-30 and HAR-34. The welds were examined using the continuous method in accordance with Peabody Testing Magnetic Particle Examination Procedure Number 21.A.3-4, Revision 1. The aforementioned examinations were done after the flaws in the licensee's coated calibration standard were satisfactorily detected.

The liquid penetrant examinations were done using visible dye, solvent removable penetrant materials, which were certified to contain permissible amounts of sulfur and halogens, as specified in the Peabody Liquid Penetrant Examination Procedure Number 23.A.1-4, Revision 1.

e. Results

No relevant indications were detected by either the magnetic particle or liquid penetrant method.

22. QA/QC Program

a. References

-- CI-240-1, Quality Assurance Program for Operating Nuclear Plants, Revisions dated August 15, 1977 and August 15, 1979.

-- FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) revised June 1977"

-- SAO-113, Quality Control Reports and Stop Work Authority, Revisions 0 and 1.

b. Analysis of Indentified Failures

During review of the documents/procedures listed above and in other sections of this report, the inspectors noted that the manner in which the QA Program is implemented for failure analysis was not clearly described in established procedures. This concern was discussed with the licensee who committed to provide NRC by December 22, 1980, a Failure Analysis Program Description, which would:

-- provide a description of the program for analysis of equipment and component failures, as to cause.

-- explain how the program detects trends not obvious to the day to day observer.

-- explain how the program analyzes the potential impact of failures, had they gone undetected, to identify new safety issues.

-- explain how the program establishes corrective action priorities based on perceived risk.

-- identify the document which establishes the position responsible for the implementation of the program.

This item is unresolved pending review of the licensee's stated actions (50-247/80-19-41).

c. Corrective Action Program

The inspector reviewed Quality Control Inspection Reports (QCIRs) to verify that:

-- QCIRs documenting conditions adverse to quality were issued to a designee for corrective action.

-- QCIRs issued for corrective action were responded to promptly.

-- QA/QC followed up open/unresolved QCIRs, issued for corrective action, and verified corrective action.

-- Corresponding MWR subject matter supported the QCIR finding.

-- Accepted completed or proposed corrective action was adequate and timely.

The QCIRs and applicable Maintenance Request Forms (MWR) reviewed were:

-- 73-2-184, Containment Ventilation Cooling System - #23 Cooling Coil (MWR 1526).

-- 75-2-47, Service Water - #23 FCU (MWR 4161 and 4873).

-- 76-2-001, Service Water - #25 FCU (MWR 4455).

-- 76-2-17, SS Spool Piece in SW #23 Fan Motor Cooler Supply Line #496.

-- 76-2-146, Emergency Power - Diesel Generators

-- 77-2-39, SWS 2" Pipe - #24 EPI SEAL Repair (MWR 6246)

-- 77-2-52, Containment Penetration - Electric and Test Penetration EPI SEAL Repair (MWR 6017)

-- 77-2-69, Ventilation - #24 FCU Brazing of Leak (MWR 6511)

-- 77-2-70, Ventilation - #24 FCU EPI SEAL Repair (MWR 6511)

-- 77-2-83, Completed MWRs Not Transmitted from Construction to the Nuclear Power Generation

-- 77-2-89, SWN-Line #45 EPI SEAL Repair (MWR 6783)

-- 78-2-27, Containment Ventilation - FCU #23 EPI SEAL Repair (MWR 7242)

-- 78-2-62, SW-SWN #23 FCU

-- 78-2-91, SWN #24 Fan Cooler EPI SEAL Repair

-- 78-2-113, Pipe Penetration Elevation 51' West Pipe Supports Residue Buildup (MWRs 6991 and 0720)

-- 78-2-120, RHR Support ACH 67/SR-52-Line #9 (MWRs 7828 and 7960)

-- 78-2-124, FSB Ventilation Weld Repair (MWR 6928)

-- 79-2-14, Containment Air Lock Penetration Electric EPI SEAL Repair (MWR 6017)

-- 79-2-27, CVCS - Repair Seals #22 Charging Pump (MWR 0065)

-- 79-2-43, SW Pump (Hold Tag 72RI140)

-- 79-2-44, BFD Lines

-- 79-2-64, SW 10" Header - FCU #21 (MWR 0374)

-- 79-2-66, SW #25 Fan Cooling Unit (MWR 0427)

-- 79-2-74, SG #24 Seismic Restraint - Temporary Oil Reservoir (MWR 790497)

-- 79-2-75, SWN - #24 FCU MASTER BOND Repair (MWR 0444)

-- 79-2-77, SW Line #10C - FCU #24 EPI SEAL Repair (MWR 0835)

-- 79-2-82, Containment Pressure Relief - PCV 1191 (MWR 0953)

-- 80-2-01, Emergency Diesel Generators Nos. 21, 22, 23 Level Gages (MWR 8638)

-- 80-2-13, Containment Cooling and Vent - FCU #25 EPI SEAL Repair (MWR 1158)

-- 80-2-17, Aux BFD - 3/8" SS GNBF6 Whitey Valve (MWR 1067)

-- 80-2-18, Aux Feedwater System - #22 Aux BFP (MWR) 1067)

-- 80-2-19, CRDM Fans - Air Scoops (MWR 1162)

-- 80-2-23, BFD - Line #5

-- 80-2-25 and 25A, ESG - Bistable PC 429E (MWR 0126)

-- 80-2-28, Containment Cooling and Vent - #25 FCU EPI SEAL Repair

-- 80-2-29, Containment Cooling and Vent - #25 FCU EPI SEAL Repair (MWR 2057)

-- 80-2-33, Ventilation - Carbon Filters FSB

-- 80-2-39, Ventilation - #25 FCU Repair With Clamp and Gasket (MWR 2850)

-- 80-2-40, CRDM - Fans

-- 80-2-41, CVCS - SHT Lo Pressure (MWR 1759)

-- 80-2-42, Secondary Blowdown - SG #21 Line 46 (MWR 2937)

-- 80-2-43, MBFD - Valve FCV 437 (MWR 2933)

-- 80-2-46, SW - FCUs 21, 23, 25 EPI SEAL Repairs (MWRs 2940, 2935, 2944)

One item of noncompliance and an unresolved item are discussed below.

(1) 10 CFR 50, Appendix B, Criterion XVI requires that measures be established for prompt identification and correction of conditions adverse to quality. FSAR Volume A, Attachment A-2 also requires prompt correction to adverse conditions identified on a Quality Control Inspection Report (QCIR). SAO-113, Revision 0, requires that the response to a QCIR to be in writing and states this should normally be done within three working days.

Contrary to the above, the established measures (e.g., QCIR system) did not assure prompt correction of conditions in that the following conditions were identified by the inspector.

-- Eight QCIRs issued between April 2, 1979 and September 4, 1980 had not been responded to as of October 29, 1980.

-- Eight QCIRs had never been responded to, but were closed by various other followup actions initiated by the QA Engineer.

-- Four QCIRs, now closed, were not responded to for 18 days to over five months.

These examples constitute an item of noncompliance (50-247/80-19-42).

(2) The inspector noted and stated his concerns that licensee Procedure SAO-113 did not clearly define what period of time constitutes prompt response to a QCIR; the time frame within which the corrective action must be completed unless otherwise agreed to; the escalation of action for nonresponses or unacceptable proposed resolutions.

The inspector was provided with a copy of a licensee Audit Report 80-40-5A (a draft), which recently identified problems in the QCIR use area; and, drafts of CI-240-1, QA-AD-23 and SAO-113 which addressed the audit findings and the inspector's concerns. Pending review of the above issued procedures and other applicable licensee action with respect to the audit findings, this item is unresolved (50-247-80-19-43).

d. Maintenance Program

During the review of maintenance program administrative controls, the inspector noted that maintenance activities are controlled by a Maintenance Work Request (MWR). Work performed per an MWR is then done using only the MWR itself; an investigative checklist; a step list (more detailed and reviewed by QA); or an approved maintenance or modification procedure. Each succeeding method is more formalized, more detailed and provides more control and documentation of the maintenance activity. As a result of this review and the review of MWRs listed in subparagraph c. above and elsewhere in this report, the inspectors identified four unacceptable items as discussed in the following paragraphs.

(1) Fan Cooler Unit leaks have been repaired from 1973 to date using an epoxy sealant and categorizing the modification as maintenance. No evaluation was made until August, 1979, to determine that an unreviewed safety question was not involved using this method of repair. The engineering evaluation performed during August, 1979, did not consider all of the post-LOCA conditions of the specific mode in which the sealant was used. The plant was operated at power after each of such repairs from 1973 until October 17, 1980. The foregoing is contrary to: 10 CFR 50, Appendix B, Criterion II, which requires programatic control over such activities; FSAR Volume A, Attachment A-2, which commits to ANSI N18.7, which in turn requires that the maintenance program provide for maintaining of safety related systems to specified

quality levels and evaluation of material useage; and, 10 CFR 50.59(b) which requires that safety evaluations be performed for changes to the facility and those records retained.

The inspectors also identified that the Station Nuclear Safety Committee did not review, as required by TS 6.5.1.6, the modifications made to Service Water Piping and Cooling Coils, associated with the Fan Cooler Units, between 1973 and October 21, 1980. These modifications were designated "temporary repairs" and were made to leaking components, using epoxy type sealants and pipe clamps.

The above constitutes an item of noncompliance (50-247/80-19-44).

(2) Despite continued Fan Cooler Units leakage and many repairs of these leaks between 1973 and October, 1980, the licensee had not made any determination of the causes of the leakage problem or recorded such action; nor had the evaluation of the causes for such leakage, which had been initiated, ever been completed.

This is contrary to: 10 CFR 50, Appendix B, and Criterion II, which requires programatic control over such activities; and FSAR Volume A, Attachment A-2, which commits to ANSI N18.7-1976, which in turn requires that the causes of malfunctions (i.e., leaks) be promptly determined, evaluated and recorded.

This is an item of noncompliance (50-247/80-19-45).

(3) Technical Specification (TS) 6.8.1 commits to ANSI N18.7-1972, Paragraph 5.1.6.1 of which requires that maintenance and modifications that may affect the functioning of safety related systems be preplanned and performed in accordance with written procedures appropriate to the circumstances.

Contrary to this requirement, site administrative procedures were not established, implemented and maintained to provide guidance as to: (1) when written and approved procedures were required for maintenance activities; and, (2) when maintenance activities constitute a modification; both of which require review and concurrence by the Station Nuclear Safety Committee. The inspector was aware of a memorandum that discussed modifications, which had been issued (March 14, 1977) by the Director of Quality Assurance. The inspector noted that these instructions did not appear to have been implemented in that: (1) there were no corresponding site or maintenance department instructions; (2) past and present Maintenance Engineers were unaware of it; and, (3) if the instructions had been implemented, the epoxy repairs discussed elsewhere in this report would have been considered as modifications, which they (the epoxy repairs) were not.

This is an item of noncompliance for failure to establish and implement appropriate procedures (50-247/80-19-46).

23. Information Documents

The licensee has a set of manuals called System Descriptions. which provide both general and detailed information on each system in the plant. There are many copies of this set of manuals in the plant and they are used by many personnel, such as engineers and control room operators, for reference. During the investigation, the inspectors noted that many portions of these system descriptions are outdated and provide incorrect information. Some are as old as 1973. The inspectors also noted that the computer manual provided in the control room for operator reference was outdated and did not agree with current computer print outs. This item is unresolved and designated Item No. (50-247/80-19-47).

24. Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable items, items of noncompliance, or deviations. Unresolved items are discussed in Details pargraphs 5, 7-12, 14-17, 19, 22 and 23 of this investigation report.

25. Management Meetings

During the period of the investigation, licensee management was periodically notified of the preliminary findings by the NRC Investigation Team. A summary was also provided at the conclusion of the investigation.

LIST OF FIGURES

PLOT OF BEST ESTIMATE OF WATER LEVEL I[illegible]ACTOR VESSEL PIT VERSUS TIME, BASED ON ACTUAL WATER LEVEL OBSERVATIONS

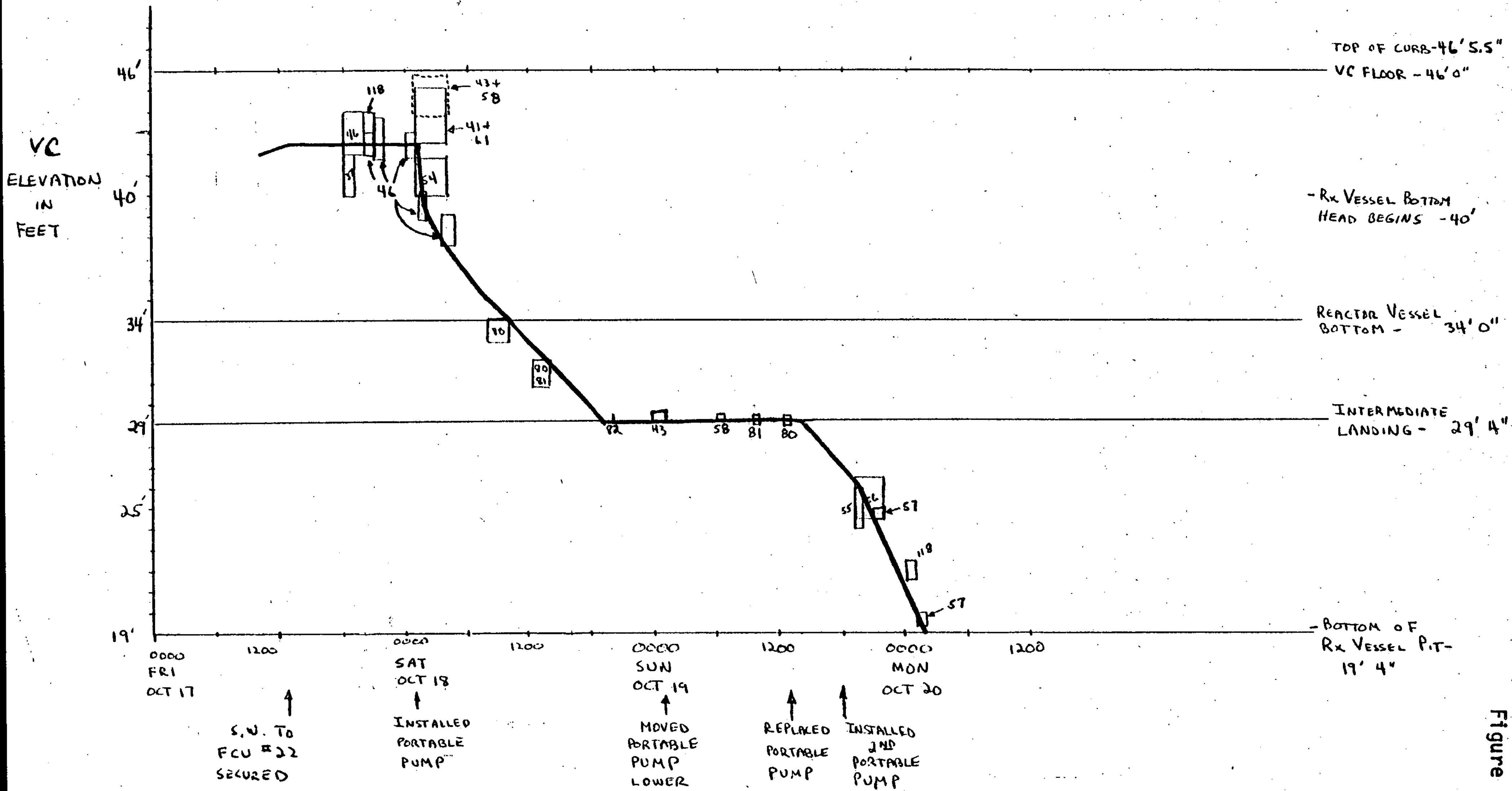
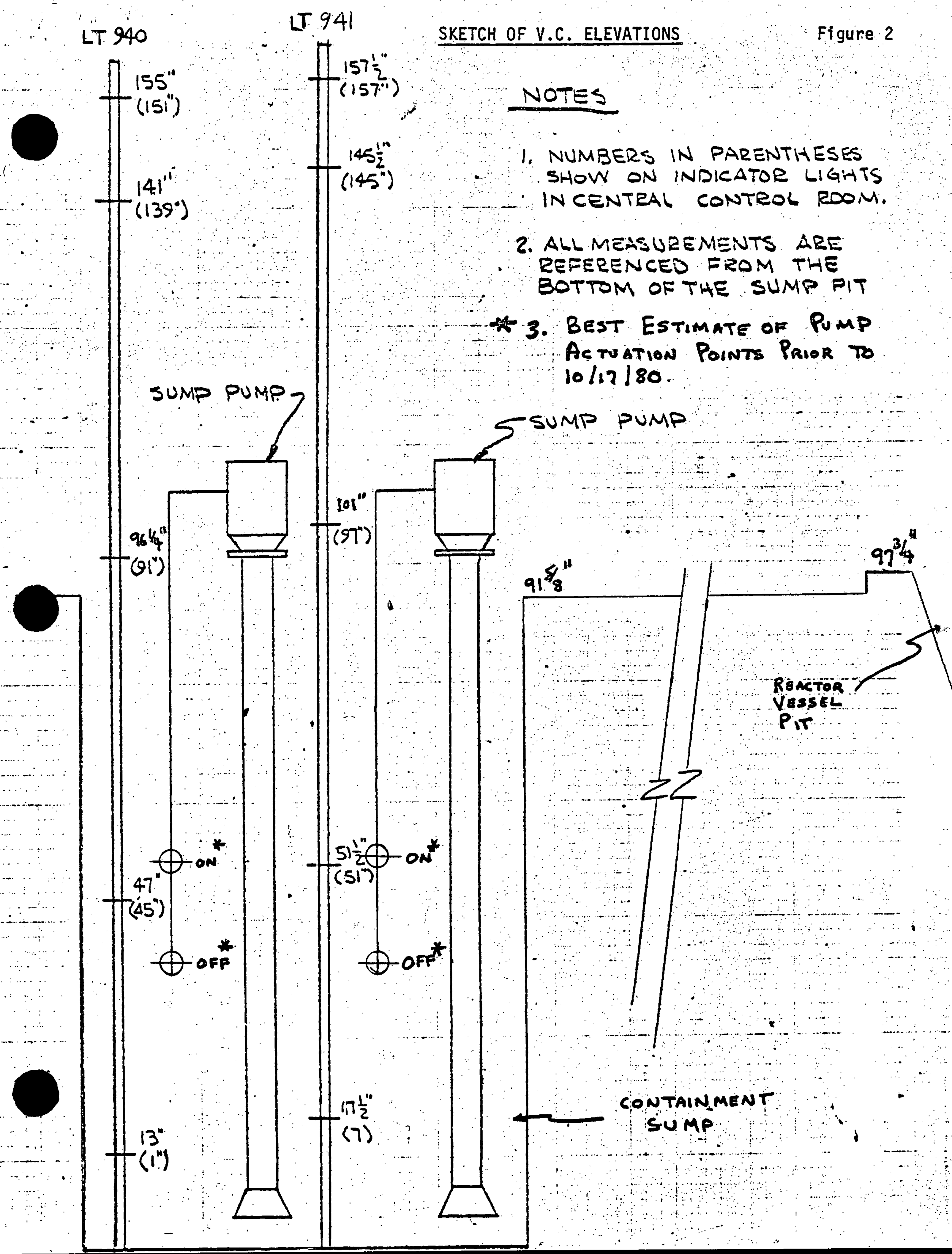


Figure 1

Note: The rectangles around individual observations represent the uncertainty associated with that observation.

SKETCH OF V.C. ELEVATIONS

Figure 2



EXISTING CONTAINMENT SUMP AND REACTOR CAVITY

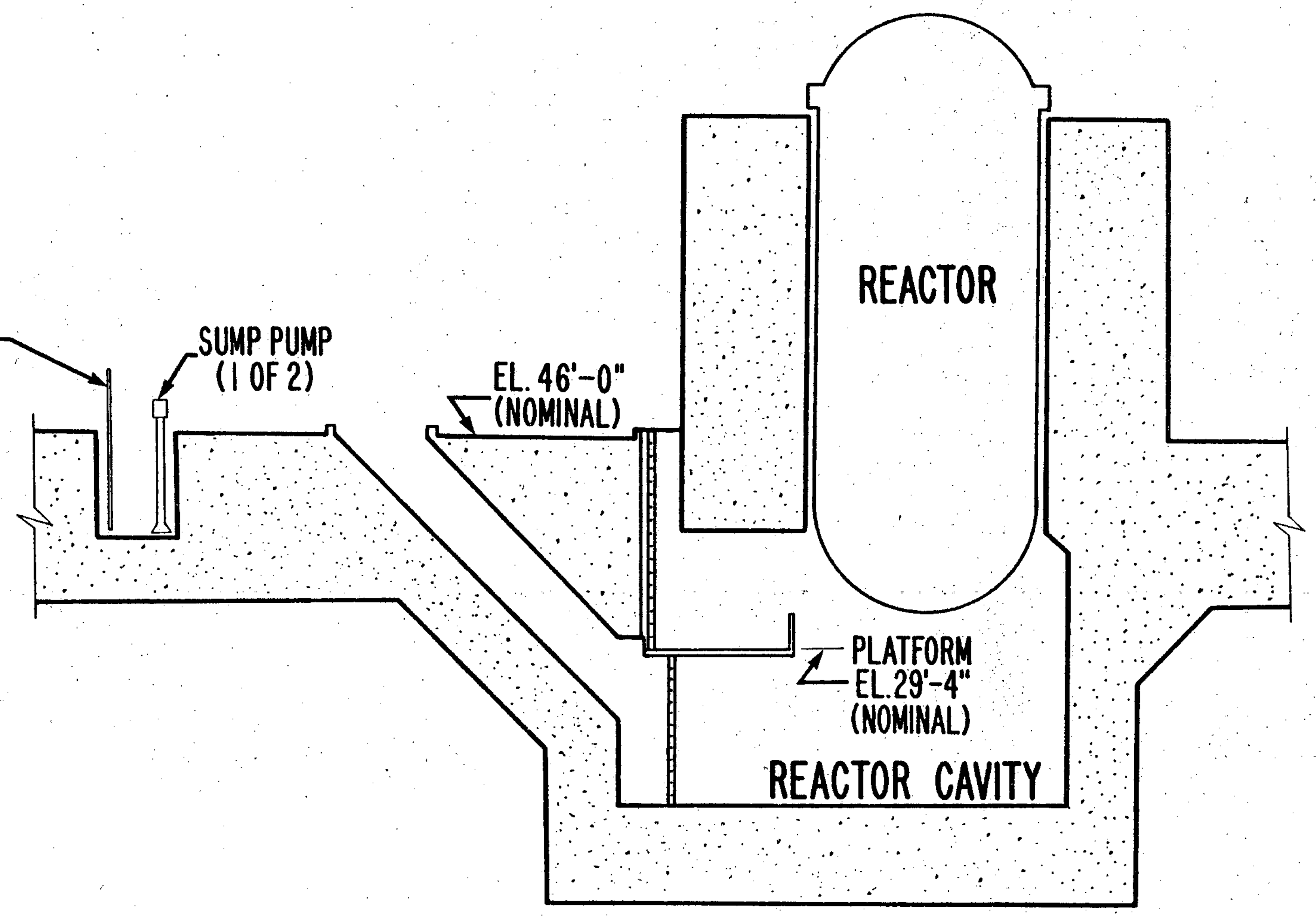


Figure 3

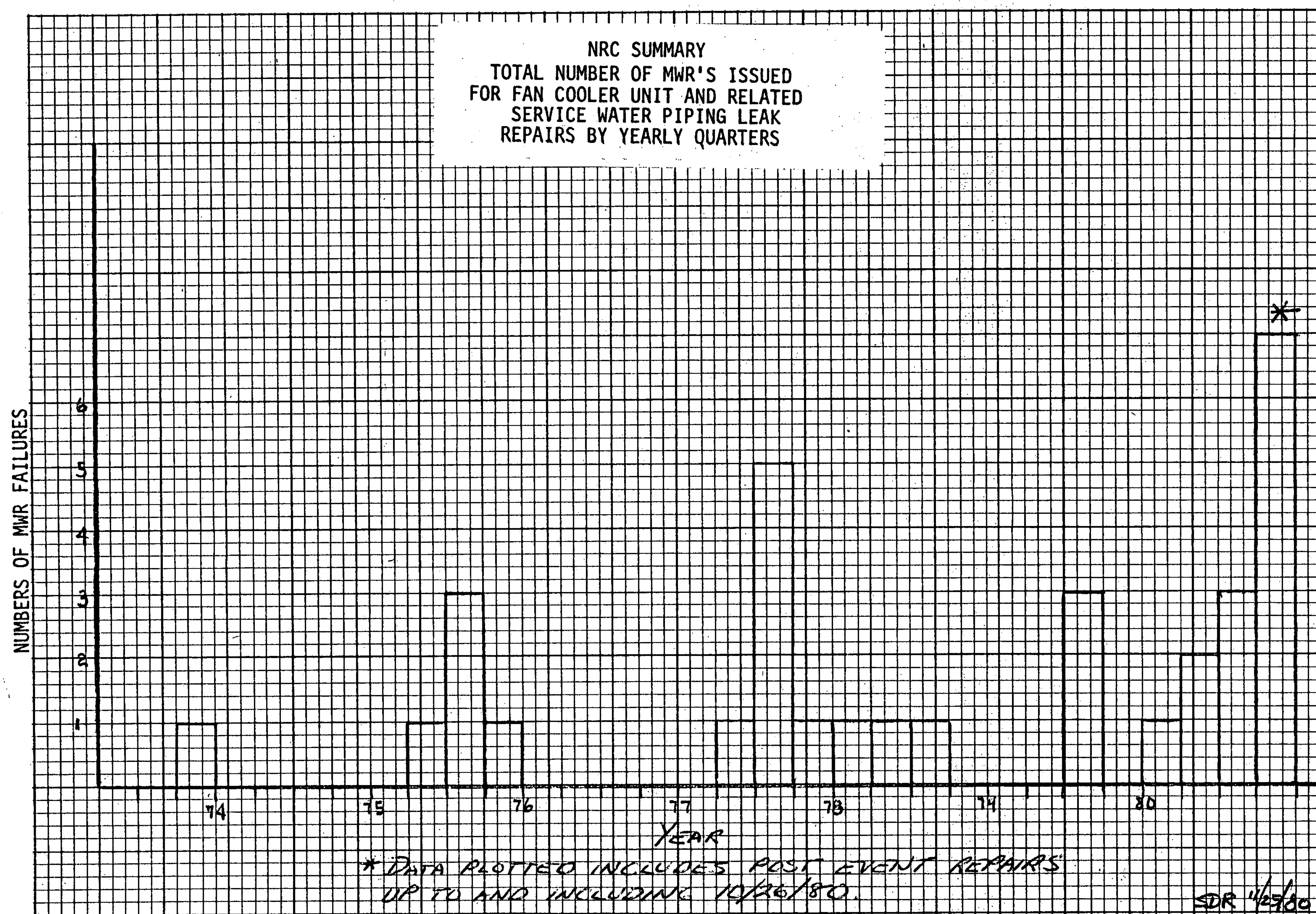

NRC SUMMARY
TOTAL NUMBER OF MWR'S ISSUED
FOR FAN COOLER UNIT AND RELATED
SERVICE WATER PIPING LEAK
REPAIRS BY YEARLY QUARTERS
NUMBERS OF MWR FAILURES
1
2
3
4
5
6
74
75
76
77
78
79
80
YEAR
*
* DATA PLOTTED INCLUDES POST EVENT REPAIRS
UP TO AND INCLUDING 10/26/80.
SDR 11/25/80

Figure 4

V.C. DEWPOINT TEMPERATURE VERSUS TIME

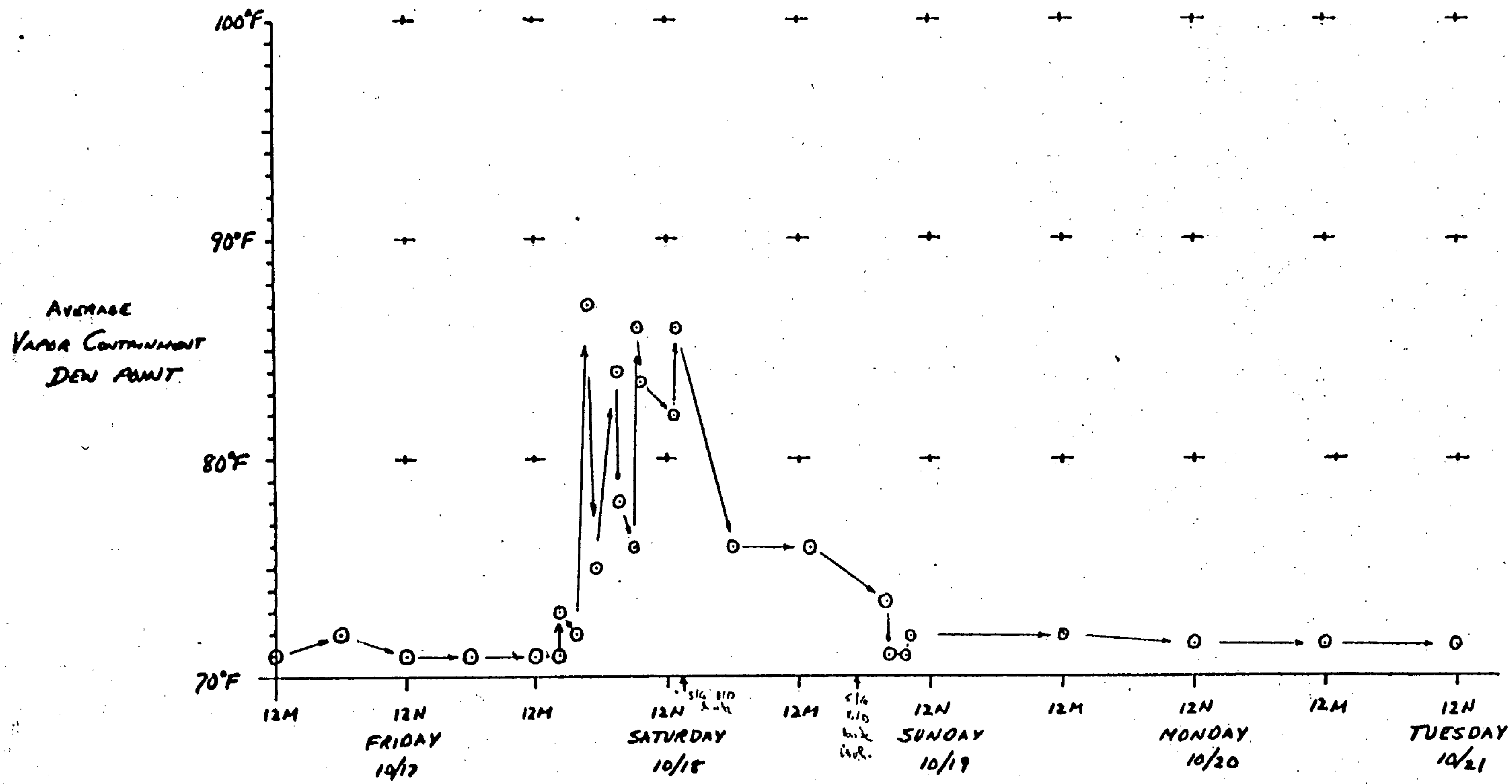


Figure 5

FAN COOLER UNIT/ SERVICE WATER LEAK CATEGORIZATION

FAN COOLER UNIT	STUB TUBE BRAZING FAILURES	TUBE FAILURES	FLEX HOSE FAILURES	CEMENT LINED PIPE FAILURES	PREVIOUS REPAIR FAILURES	FIELD REPLACEMENT S.S. WELD FAILURES	BRAZED JOINTS OTHER THAN STUB TUBE-FAILURES	TOTAL CORROSION AND JOINING FAILURES
21	2	1						3
22			2	1				3
23		2		3		2	2	9
24	1			2	3		1	7
25	2	2(1)	1	2	3			10
TOTAL	5	5	3	8	6	2	3	32

NOTE: (1) INCLUDES 5 TUBE FAILURES IN ONE TUBE AS ONE (1) FAILURE

FIGURE 6

ACRONYMS AND UNITS OF MEASURE

1. ACRONYMS

C.O.E	Chief Operations Engineer
F.C.U.	Fan Cooler Unit
I&C	Instrumentation & Control
IAL	Immediate Action Letter
IE:HQ	Office of Inspection and Enforcement Headquarters
IP 2	Indian Point 2
HAZ	Heat Affected Zone
M.S.I.V.	Main Steam Isolation Valve
MWR	Maintenance Work Requests
NaCl	Sodium Chloride
N.D.E.	Non-Destructive Examination
NI	Nuclear Instrumentation
N.P.G.	Nuclear Power Generation
N.P.O	Nuclear Plant Operator
N.R.C.	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
O.C.C.	Operations Control Center
Q.C.I.R.	Quality Control Inspection Report
P.M.	Plant Manager
P.W.H.T.	Post Weld Heat Treatment
R.C.S.	Reactor Coolant System
R.V.	Reactor Vessel
S/G	Steam Generator
S.F.S.	Support Facility Supervisor
S.W.S.	Senior Watch Supervisor

Tavg	Average Reactor Coolant System Temperature
T.E.D.	Technical Engineering Director
T.S.	Technical Specification
V.C.	Vapor Containment
V.P.	Vice President
W.H.U.T.	Waste Hold-up Tank

2. UNITS OF MEASUREMENTS

gpm	gallon per minute
mg	milligrams
mg/dm^2	milligrams per decimeter squared
mls	milliliters
MWe	Megawatts-electric
ppm	parts per million
psig	pounds per square inch-gage
uc/cc	microcuries/cubic centimeter
^oF	degrees Fahrenheit
%	percent
#	number

ENCLOSURE 1

NRC SEQUENCE OF EVENTS
INDIAN POINT 2
WATER LEAKAGE INTO CONTAINMENT

WEDNESDAY, OCTOBER 1, 1980

PLANT STATUS: Reactor at 100% power, Tavg at 548°F, Boron Concentration at 185 PPM, Turbine Generator at 820 MWE, Vapor Containment at 108°F and 0.1 psig.

--- Vapor Containment (V.C.) entered while at 100% power to repair leaks on Fan Cooler Unit (F.C.U.) #25. These repairs were prompted by a desire to reduce the measured inleakage to the Waste Holdup Tank (W.H.U.T.).

FRIDAY, OCTOBER 3, 1980

PLANT STATUS: Reactor at 100% power, Tavg at 548°F, Boron Concentration at 180 PPM, Turbine Generator at 820 MWe, Vapor Containment at 111°F and 0.4 psig.

--- V.C. entered while at power to repair leaks on F.C.U. #21. During entry, the floats, associated with at least one V.C. sump pump controller and both V.C. sump level indication systems were lifted by hand to check their freedom of operations. No apparent problems noted.

--- Subsequent measured inleakages to the W.H.U.T. showed a marked reduction to historical values. The V.C. sump level indication system continued to show a water level between the 45 inch and 91 inch level switches on one instrument stalk, but now showed a water level between the 51 inch and 97 inch level switch on the other stalk. All F.C.U. weir levels indicated below 4 inches.

TUESDAY, OCTOBER 14, 1980

PLANT STATUS: Reactor at 100% power, Tavg at 549°F, Boron Concentration at 145 PPM, Turbine Generator at 830 MWe, Vapor Containment at 111°F and 0 psig.

--- High weir level alarm received on F.C.U. #22, reading above 7 inches. Licensee evaluated this alarm and declared the alarm channel inoperable. This response action was based on no observed increase in V.C. radiation, particulate, dew point or sump level detector readings; no observed increase in calculated W.H.U.T. inleakage or reactor coolant system outleakage; and, no observed change in F.C.U. #22 weir level indication, when operators closed the Service Water supply and return lines to F.C.U. #22. (Note: The Service Water return line isolation valve has since been found to leak excessively).

THURSDAY, OCTOBER 16, 1980

PLANT STATUS:	Reactor at 100% power, Tavg at 549°F, Boron Concentration at 160 PPM, Turbine Generator at 830 MWe, Vapor Containment at 113°F and 0.2 psig.
0940	Started #22 Containment Spray pump for a surveillance test.
1008	Secured #22 Containment Spray pump. Test acceptance criteria met.
1645	Notified by consultants, Woodward & Clyde, that there was a possible earthquake at 1302 hours on 10/15/80, in the vicinity of the Croton Reservoir. The event was too small to determine the exact location or to register a number on their scale. However, motion was detected by some of their instruments and no blasting was known to have occurred in that area at that time (the Croton Reservoir is about 12 miles from Indian Point at its nearest point).
	Notified required personnel and agencies.
1705	Completed check of Control Room and plant for evidence of damage to equipment and structures; none found.
1707	Notified by Unit #3 that no motion was detected by their seismic recorders.
1708	Notified NRC via hot line of potential earthquake report, response actions and results.
1733	Notified NRC Resident Inspector of potential earthquake report, response actions and results.

FRIDAY, OCTOBER 17, 1980

PLANT STATUS:	Reactor at 100% power, Tavg at 549°F, Turbine Generator load at 820 MWe, Boron Concentration at 130 PPM, Vapor Containment at 110°F and 0.3 psig.
Approx. 0030	Received high alarm on Nuclear Instrument Power Range Channel N42-Axial Flux Offset.
Approx. 0030	Operators noted nightly heat balance readings appeared abnormal. Performed quadrant power tilt calculations. Tilt indicated 1.02 upper and 1.03 lower. Requested I&C to check instrumentation. Channel N42 indicated high positive axial flux tilt. Suspected bad power range channel. Performed Quadrant tilt calculations on 1/2 hour basis.
Approx. 0045	Chief Operations Engineer was called at his home and and informed of the problem with Channel N42. He then called the Plant Manager and informed him of the problem.
Approx. 0100	Reduced load from 100 percent due to Nuclear Instrument System problems in attempt to correct flux tilt.
---	Reactor Engineer was requested to come to plant by the Senior Watch Supervisor (S.W.S.). Was informed bottom detector on Nuclear Instrument Channel N42 was reading less than expected.
0210+	Load reduced to about 90 percent.
Approx. 0300	Reactor Engineer arrived onsite.
Approx. 0300	Performed check on channel N42; all electronic circuits in Control Room appeared acceptable.
Approx. 0325	Performed incore flux map.
0355	Determined flux distribution was normal and concluded instrument channel had failed. Nuclear Instrument Power Range Channel N42 was declared inoperable.
---	S.W.S. called the Chief Operations Engineer at home and requested he get permission to operate above 70 percent power with one Power Range Nuclear Instrument Channel inoperable, as is required by licensee's procedures.

0400 Removed control power fuses from Channel N42. This caused a rapid indicated power decrease in the N42 core quadrant, resulting in a rod drop alarm and turbine runback actuation (due to rod drop protection circuitry). Experienced Turbine Runback from 700 MWe to 500 MWe.

--- During telephone discussion, the Plant Manager gave permission to the Chief Operations Engineer to operate up to 100 percent power with one Power Range Nuclear Instrument Channel out of service.

--- Licensee's Operations Control Center (O.C.C.) and Chief Operations Engineer informed of runback.

0408 Axial flux offset alarm.

0415 High Tavg alarm.

0418 Tavg increased with lower steam demand and control rods in manual. Decided movement of control rods undesirable. Dispatched operators to local turbine generator controls. Operator turned the load limiter in the wrong direction, driving the turbine generator load from 500 MWe to about 100 MWe. Experienced a Reactor Trip from 70% power. First out annunciator indicated trip from Low Low Steam Generator Level #23. Computer sequence of events log indicated Reactor trip due to High Pressurizer Pressure.

--- Chief Operations Engineer and the O.C.C. were informed by the S.W.S. by telephone of the trip.

--- During telephone discussion, the Plant Manager agreed with the Chief Operations Engineer to start up plant with only three power range nuclear instrument channels operable. Each reportedly was confident the cause of the trip was understood and that a delay in startup was not warranted. The decision to promptly return to power was possibly tempered by the knowledge that xenon buildup would prevent return to criticality if actions were delayed, due to minimal excess reactivity left in core.

0435 Licensee called NRC on "Hot Line." IE:HQ log indicates: trip from 60% power caused by failure of power range channel #42; failure caused turbine runback, and steam generator level oscillation causing reactor trip; all systems operated as expected; and plant may go back to power with channel tripped.

	Review of IE:HQ tapes indicates plant further reported no safety injection or radioactivity release occurred.
Approx. 0451	Completed critical rod estimate. Reactor Trip breakers shut.
0540	Began pulling rods to go critical.
0600	Reactor Critical. O.C.C. informed.
0620	V.P.-Power Generation was updated on events of the morning by the O.C.C.
---	Holding approximately 3% power, diluting to compensate for xenon buildup.
Approx. 0830	During a telephone discussion, the licensee's Techncial Engineering Director informed the NRC Resident Inspector (RI) of the first reactor trip. Subsequently, the licensee again called the Resident, confirming they had reported the trip to NRC via the emergency phone.
Approx. 0840	NRC Resident Inspector informed his Section Chief of first reactor trip with reactor now critical.
Approx. 0847	I&C Department working on power range nuclear instrumentation. Checks of Channel N42 show sluggish response. Technician decided to do a comparison check. Took all of Channel N42 trips out of the circuit with the exception of Overpower Delta "T" and Overtemperature Delta "T". Reactor tripped on Overpower Delta "T" (2 out of 4 logic).
---	Plant Manager agreed with Chief Operations Engineer to start up plant. Each reportedly was confident the cause of the trip was understood and that a delay in startup was not warranted.
---	Prepared estimated critical position (Bank D at 145 steps).
Approx. 0900	I&C Engineer learned of grounded nuclear instrument detector on Channel N42. Detector signal cable center conductor to ground and center conductor to shield conductor resistances both read about 2000 Ohms.
0902	Reactor Trip breakers shut.
---	Pulling rods to go critical.

Approx. 0920	Licensee called NRC on "Hot Line." IE:HQ log indicates: trip from 3% power at 0850 hours; technicians repairing power range Channel N42 were careless in cabinet; tripped on Overtemperature Delta "T" Channel 42; and, returning to power. Review of IE:HQ tapes indicates plant further reported to be in hot shutdown; expecting to go critical within next hour; and, no safety injection or radioactivity release occurred.
Approx. 0930	Technical Engineering Director discussed second Reactor trip with NRC Resident Inspector.
---	Plant Manager decided to take the plant to hot shutdown to replace failed nuclear instrument detector. The decision to shutdown was reportedly influenced by the requirement to conduct daily flux maps. (with one nuclear channel inoperable), the concern for wear on the incore instrument system. (during the conduct of these procedures), the increased probability of a spurious Reactor trip (with one channel tripped), and the recognition that spare parts were available and the fix would only take a couple of hours. (since union personnel would assist in the repairs if the plant was shutdown).
0950	Reactor critical.
0950+	Operators directed to shutdown Reactor by the Chief Operations Engineer, who had just entered the Control Room, conveying the Plant Manager's decision.
1000	Plant Manager informed O.C.C. that failed power range detector would be replaced and that unit should be back on line by 1700 hours.
1010	Reactor Subcritical - Shutdown banks still out.
1015	Shut Main Steam Isolation Valves (M.S.I.V.s) to reduce cooldown rate. Broke condenser vacuum. One M.S.I.V. did not close fully. Operator able to close manually.
Approx. 1030	Preparations begun to enter V.C. for Channel 42 detector replacement.
Approx. 1100	Technical Engineering Director informed NRC Resident Inspector that plant had been shutdown to repair Channel N42.

Approx. 1145	During the V.C. entry the licensee planned to pull the detector in line with its removal hole, from elevation 46 feet, and replace the detector from the refueling cavity. If elevation 95 feet lights were found off, plans were to exit and regroup.
1200	V.C. entry. Eight personnel (5 I&C Technicians and 3 Health Physicists) entered. Five individuals went to elevation 95 feet and found lights out. Three individuals went to elevation 68 feet and then elevation 46 feet. On elevation 68 feet, water was seen on floor around F.C.U. #22. On elevation 46 feet, noted water coming from ceiling under F.C.U. #22 and from F.C.U. #22 weir. Floor of elevation 46 feet was noted to have several inches of water covering it.
Approx. 1210	Crew out of V.C. Report of observations was made to control room and Plant Manager. Plant Manager informed Operations personnel would investigate.
---	Operators verified isolation valves open on V.C. sump pump discharge line to the W.H.U.T.
Approx. 1230	Isolated Service Water supply and return to F.C.U. #22, due to Service Water leak.
---	NRC Resident Inspector informed Section Chief that plant was in hot shutdown to repair nuclear instrumentation.
1320	Crew back in V.C. for second attempt to install Detector N42. Planned to use flashlights on elevation 95 feet and rubber boots on elevation 46 feet.
1335	A Support Facility Supervisor (S.F.S.), a Senior Reactor Operator, entered the V.C. at the direction of the S.W.S. to investigate the water on the floor. Both V.C. sump pumps were found stopped and F.C.U. #22 was found to have a Service Water Leak. Manual actuation of both V.C. Sump Pump floats caused one pump to start. Replacement of fuses and possible resetting of the thermal overloads started the second V.C. Sump Pump.
Approx. 1345	On elevation 95 feet, crew noted high temperature and humidity in refueling cavity and steam-like vapor exiting from holes in the detector well covers. A water film covered the electrical conductors in the hole. On elevation 46 feet, noted 4 F.C.U. weirs overflowing, including F.C.U. #22 weir, at a reduced rate. A lot of water was still dripping from the elevation 46 feet overhead, under F.C.U. #22. The depth of the water on the floor inside the missile shield was found to be deeper and was characterized as 2 to 4 inches or ankle deep.

1405	S.F.S. exited V.C. to obtain tools to inspect the leak on F.C.U. #22 Service Water return line. V.C. Sump Pump #29 had been found with two blown fuses and V.C. Sump Pump #210 had malfunctioned due to a cocked float assembly.
1430	S.F.S. returned to V.C. and removed the insulation from F.C.U. #22 Service Water return line. Hole found in 10 inch pipe at a weld. The S.F.S. exited the V.C. 20 minutes later and informed the Control Room of his findings.
Approx. 1430	Plant Manager and Control Room notified by the I&C Engineer of his inability to replace Channel N42 detector due to hot-humid vapor issuing from detector well.
---	During a meeting in the Plant Manager's office the Technical Engineering Director questioned what water level had been observed on the elevation 46 feet floor. When informed that the level had reached only 2 to 4 inches, he reportedly indicated the curb on the openings leading to the Reactor Vessel Pit was 6 inches tall and it was then concluded that water could not have flowed into the pit.
	During the same meeting it was agreed the Technical Engineering Director would inform the NRC Resident Inspector.
---	Discussions with licensee management indicated no manager believed there existed a requirement to notify NRC of the Service Water leakage collected on the V.C. floor; nor could anyone even recall a discussion of the potential need to make such a report.
1522	The Technical Engineering Director attempted to contact the NRC Resident Inspector. Left message on answering machine requesting a return call. No reason for the call was recorded. Licensee reportedly intended to inform Resident of the M.S.I.V. closure failure and the discovery of a couple of inches of Service Water on the V.C. floor.
Approx. 1600	Maintenance made V.C. entry to repair F.C.U. #22 using a rubber backed stainless steel sleeve clamp for the 10 inch service water outlet line leak.

---	Licensee planned to return to power before 2300 hours with three operable power range nuclear instruments. Operators directed to keep on top of V.C. sump pumping rate.
---	V.P. Power Generation notified by Plant Manager of F.C.U. leaks.
Approx. 1800	S.F.S entered V.C. to verify no water had gotten into Reactor Vessel Pit. Found water in Pit about 4 feet below locked grating on elevation 46 feet. (This is first reported evidence of water in Reactor Vessel Pit.) The S.F.S. checked the lights for the Reactor Vessel Pit Sump Pumps and believed one was lit and one was out. He further observed an acceptable leak repair test of F.C.U. #22, noted a water leak from near F.C.U. #23, and then left the V.C.
Approx. 1830	S.F.S. notified Chief Operations Engineer and Control Room of his findings.
Approx. 1900	Plant Manager informed by the Chief Operations Engineer that the Reactor Vessel Pit was flooded, that leaks on the F.C.U.'s were being repaired, and that the V.C. Sump Pumps were pumping the water out. This information was not passed on to the V.P.-Power Generation at this time.
Approx. 1945	Cleared permit and started F.C.U. #22.
Approx. 1947	Tagged out F.C.U. #23 for leak repairs.
Approx. 2045	Licensee gathered equipment to install and operate portable submersible pumps. A Reactor Operator Trainee entered the V.C. to determine if the Reactor Vessel Pit Sump Pumps were running. Found pump with the moisture detector alarm lit (falsely believed to indicate pump running) to have power downstream of the line fuses. Trainee hung two strings with weights attached; one touched water surface and one extended several feet below the water level. Trainee reported the Reactor Vessel Pit water level had dropped 4 inches during his entry. This convinced the Trainee that the Reactor Vessel Pit Sump Pumps were pumping.
Approx. 2240	V.C. sump isolated. W.H.U.T. being transferred to Unit 1.

SATURDAY, OCTOBER 18, 1980

PLANT STATUS:	Reactor subcritical in a hot shutdown mode awaiting return to power. Vapor Containment closed. The water in the W.H.U.T. being transferred to Unit 1.
Approx. 0030	Opened V.C. airlock for entry team (4 individuals) to set up portable submersible pump. Team reported puddles on elevation 46 feet and water level somewhere between 3 inches to 4 feet below elevation 46 feet grate over the Reactor Vessel Pit. Team exited to get a key for the lock on the grate. F.C.U. #22 reported to have another leak.
Approx. 0100	Team entered V.C., unlocked the Reactor Vessel Pit grate, installed portable air driven submersible pump on the Reactor Vessel Pit Intermediate Landing and commenced pumping the Reactor Vessel Pit to the V.C. Sump. A V.C. Sump Pump float was observed to be caught again and had to be freed to start the pump.
Approx. 0130	One team member reported seeing steam in vicinity of Steam Generator (S/G) #21 on V.C. elevation 68 feet. Another team member tried to start a Reactor Vessel Pit Sump Pump by replacing blown fuses; but each time the fuses were replaced, they blew within 3 seconds of closing the electrical disconnect.
Approx. 0130	Maintenance working on F.C.U. #23 motor cooler leak.
0135	Opened V.C. sump isolation valves to the W.H.U.T. W.H.U.T. level at 44% when valves were opened. W.H.U.T. being transferred to Unit 1.
Approx. 0200	Average of Dew Point temperatures jumped from an average of 71°F to about 74°F and then slowly decreased.
Approx. 0200	Reactor Vessel Pit Sump Water Level was reported to be dropping as the portable submersible pump discharged to the V.C. Sump.
---	Air operated portable submersible pump may have failed at this point.
Approx. 0330	Reactor Vessel Pit Water Level reported to have dropped slightly from previous mark, and apparent rate of drop was significantly less than previous observation.

Approx. 0340	Average of Dew Point temperatures had decayed to about 72°F, but now turned and climbed to about 86°F, over a period of about one hour.
Approx. 0445	Average of Dew Point temperatures had peaked at about 86°F and started rapid decrease to about 76°F, over next 45 minutes.
Approx. 0530	Average of Dew Point temperatures bottomed at about 76°F and now started less rapid rise to about 84°F, over a period of two hours.
Approx. 0530	V.C. entry party noted Reactor Vessel Pit water level decreasing.
---	Operator instructed to compute estimated critical position for 0900 hours on 10/18/80.
Approx. 0730	Average of Dew Point temperature peaked at about 84°F and then began slow decrease to about 77°F, over a period of about one and one half hours.
0730+	Repaired V.C. sump floats, which had become cocked and stuck again, and inspected the Reactor Vessel pit. (Water level 13 ladder rungs down, elevation 34 feet.)
Approx. 0900	Average of Dew Point temperatures jumped from about 77°F to about 82°F, where it remained for about three and one half hours.
1210	O.C.C. informed unit expected to go critical approximately 1400 hours.
1227	S.W.S. toured containment and noted water level in Reactor Vessel Pit just above the portable sump pump on the intermediate level. The portable pump was pumping. Found leak on #21 S/G blowdown line and #25 F.C.U. S.W.S. exited the V.C. at about 1400 hours.
Approx. 1240	Average of Dew Point temperatures jumped to about 86°F, where it remained for about one and one half hours.
Approx. 1300	#23 F.C.U. Service Water flow resumed.

1350+	(LATE LOG ENTRY) (1) V.C. Entry, (2) #25 F.C.U. Service Water leak (secured), (3) Possible leak on #21 F.C.U., (4) Estimate Reactor Vessel Pit level about 15th rung from elevation 46 feet.
1400+	(LATE LOG ENTRY) W.H.U.T. level increased from 23% to 33%; still transferring water to Unit 1.
---	S.W.S. informed Chief Operations Engineer of S/G blowdown line leak, who in turn informed the Plant Manager.
Approx. 1420	Average of Dew Point temperatures began decay from 86°F to about 76°F, were it remained till about 0100 hours on Sunday, 10/19/80.
Approx. 1435	Completed repairs to motor cooler of #23 F.C.U. Started #23 F.C.U. for test.
Approx. 1500	V.P.-Power Generation notified by the Plant Manager of discovery of S/G. blowdown line leak and plans for repairs.
1605	O.C.C. informed unit will be delayed in coming back. Assistance requested for obtaining qualified welders for System Generator Blowdown leak repair.
Approx. 1715	Two Nuclear Plant Operators (N.P.O.'s) entered V.C. Reactor Vessel Pit portable sump pump discharging to containment sump and two to three inches of water on elevation 46 feet floor, inside ring wall. Located S/G blowdown line leak and noted small amount of steam from leak. Isolated S/G blowdown line. Located additional small leaks on #21 and #22 F.C.U.
Approx. 1930	Nuclear Side N.P.O. entered V.C. Verified Pressure Relief Tank drain to V.C. sump shut, and Reactor Coolant Drain Tank drain to V.C. sump open, per normal line up.
Approx. 2100	Nuclear Side N.P.O. entered V.C. to show to maintenance the #21 S/G blowdown line leak and to check on the portable sump pump on the intermediate level. Pump was in a few inches of water and probably not moving any water.

SUNDAY, OCTOBER 19, 1980

PLANT STATUS:	Reactor subcritical in a hot shutdown mode awaiting return to power. The Vapor Containment was closed but unlocked with pressure relieving in progress. The water in the W.H.U.T. was being transferred to Unit 1.
Approx. 0100	Air operated pump lowered about 5 feet below intermediate landing of Reactor Vessel Pit. Water level just above intermediate landing. Elevation 46 feet floor reportedly dry with some puddles.
0250	Commenced work on F.C.U. #21 cooler leak.
0400	Started F.C.U. #25 for test following leak repairs.
Approx. 0555	Opened inlet valve to F.C.U. #21.
Approx. 0600	V.C. entry made to repair portable submersible pump in Vessel Pit, which had stopped. Water level at intermediate landing grating. Could not fix pump. Lubricator had run out of oil and pump had seized.
0625	Started F.C.U. #21.
---	Repairs completed to V.C. Sump Pump float operated controllers.
0917	S.W.S. toured V.C. W.H.U.T. and V.C. Sump were full. One to two inches of water found on floor of elevation 46 feet. Found float on V.C. Sump Pump's controller loose. Reactor Vessel Pit Intermediate Landing level found awash. No evidence that either installed Reactor Vessel Pit permanent sump pump was working. Left V.C. at 1003 hours.
Approx. 0930	Repaired float ball for V.C. Sump Pump controller.
Approx. 1030	S.W.S. and Chief Operations Engineer decided to drill hole in Reactor Vessel Pit Sump Pump's discharge line to preclude siphoning V.C. sump to Reactor Vessel Pit.
1145	V.P. Power Generation called O.C.C. for update on status of plants.
---	V.P. Power Generation called S.W.S., learned water found in Reactor Vessel Pit, believed this was connected with Steam Generator Blowdown Line leak reported earlier, and offered to assist in finding additional pumps.

Approx. 1230	Nuclear Side N.P.O. made V.C. entry to put new portable submersible pump in the Reactor Vessel Pit. Failed portable pump removed and one hung about 5 feet below intermediate landing.
1345	F.C.U. #25 secured for maintenance.
1430	Drilled hole in Reactor Vessel Pit Sump Pump's discharge line. Noted no water came out, implying pumps not running.
---	Licensee planned startup once the Reactor Vessel Pit water level dropped below all incore instrument conduits and the F.C.U. leaks were repaired.
Approx. 1700	Meggered the 2 reactor cavity sump pumps: No. 1 grounded, overload tripped and breaker tripped; No. 2, one phase grounded, overload tripped, and closing coil failed. V.C. Sump Pumps in auto with floats operable.
Approx. 1915	V.C. entry to install second portable submersible pump in Reactor Vessel Pit. First pump was discharging water to the V.C. sump. Water level in the Reactor Vessel Pit was about 4 feet below the intermediate landing.
1930	O.C.C. informed continuing to pump Reactor Vessel Pit.
2000	Nuclear Side N.P.O. entered V.C. to do additional work on F.C.U. #22 normal air flow outlet valve indication.
Approx. 2030	Water in Reactor Vessel Pit nine rungs below intermediate landing. (Elevation 24' 8".)
Approx. 2155	Shut V.C. sump isolation valves.

2200	Opened Condenser Vacuum Breakers.
2230	Second Reactor Vessel Pit Portable Pump still not working. N.P.O. sent in to correct improper hook up. Water level about 4 feet below intermediate landing. First pump still working.
Approx. 2330	Opened inlet valve on F.C.U. #25.

MONDAY, OCTOBER 20, 1980

PLANT STATUS:	Reactor subcritical in a hot shutdown mode awaiting return to power. The Vapor Containment airlock door was closed with people working inside on F.C.U.'s.
Approx. 0025	Completed repairs on F.C.U. #25 and valved it into service.
0125	Started F.C.U. #25 for test. Showed no excessive leakage.
Approx. 0115	Second Reactor Vessel Pit portable pump off again. Water at 14th rung below intermediate landing (elev. 19' 8"; 4" of water on bottom of pit).
---	V.C. Sump pumps isolation valves closed.
Approx. 0145	Opened V.C. Sump isolation valves. W.H.U.T. level at 86%.
Approx. 0205	V.C. Sump isolation valves closed with W.H.U.T. level at 94%.
0305	During V.C. entry found water on floor outside missile barrier, where it had previously (prior to midnight) been reported dry. Operators went into V.C. to remove portable submersible pumps if water level was found below incore instrument conduits in Reactor Vessel Pit. Otherwise, were directed to add oil to the portable submersible pumps and continue pumping the Reactor Vessel Pit. Water level was found below conduits in pit.
0530	O.C.C. informed by S.W.S. that the shift was closing out the Vapor Containment, was preparing to go critical, and expected to be on line by 1000 hours.
Approx. 0530	Reactor Vessel Pit essentially dry. Two portable submersible pumps had been removed from the Reactor Vessel Pit and placed on floor outside missile barrier on elevation 46 feet floor.
Approx. 0610	Performed V.C. Closeout. V.C. sump pumped down all the way; final check on all F.C.U.'s found no leaks on cooling coils, motor coolers, or external piping. Removed air hoses from Reactor Vessel Pit and closed and locked the grating. Recommended entry be made in next 24 hours to check for leaks. Water was observed to still be flowing from F.C.U. weir #22. V.C. sump isolation valves were closed with W.H.U.T. level at 95%.

Approx. 0630	Commenced control rod withdrawal for normal startup.
0650	Reactor Critical. O.C.C. informed.
0700+	W.H.U.T. still being transferred to Unit 1.
Approx. 0730	Ansaphone in NRC Resident Inspector's office interrogated. Message from licensee indicated: Time 3:22 p.m.; 10/17; requests return call. No reason was given.
Approx. 0745	NRC Resident Inspector returned call to Technical Engineering Director, found him out, and requested call back.
Approx. 0800	Manager, Nuclear Power Generation (N.P.G.), who had been on vacation since 10/14/80, arrived on site and was briefed on plant status.
Approx. 0830	Manager, N.P.G. made decision to shutdown, based on concern about chlorides on stainless steel incore instrument conduits. V.P.-Power Generation was updated on plant status and concurred in decision to shutdown.
---	Licensee initiated effort to compute volume of water pumped from V.C.. Chemistry and Radiation Safety Director was instructed to swipe survey incore instrument conduits to determine level of flooding in Reactor Vessel Pit.
0955	Reactor manually shutdown from less than 1% power. Turbine never taken off turning gear.
Approx. 1010	Opened V.C. sump isolation valves with W.H.U.T. level at 80%.
Approx. 1050	Closed V.C. sump isolation valves with W.H.U.T. level at 95%.
1110	Made preparations for V.C. entry.
Approx. 1115	Licensee returned call to NRC Resident Inspector. Stated that some water was found on containment floor over weekend and plant was critical this morning, but now in hot standby.

Approx. 1200	Licensee sampled water in Reactor Vessel Pit; found 3400 ppm NaCl. Licensee swiped incore instrument conduits; found levels from 0.025 to 1.53 mg/100 cm^2 of chlorides, from point above elevation 46 feet to Reactor Vessel insulation, with results increasing as Reactor Vessel was approached. The highest observed level was associated with an encrustation, believed by the licensee on 10/20/80 to be unrelated to this flooding event.
---	V.P.-Engineering notified of water on V.C. floor and in the Reactor Vessel Pit.
1300	Crew out of V.C.
---	Manager, N.P.G. informed NRC Resident Inspector that preliminary water inventory balances indicated about 45,000 gallons of water were pumped from the V.C.
Approx. 1605	NRC Resident Inspector called Region I; notified Acting Section Chief of V.C. flooding, that preliminary inventory calculations indicated 45,000 gals. of liquid were removed from the V.C.. Question of potential wetting of Reactor Vessel was raised by Region I.
Approx. 1635	Shut V.C. sump isolation valves with W.H.U.T. level 96%.
1645	Region I called licensee. Licensee indicated Reactor Vessel was not wetted. Chief Operations Engineer and Assistant Chief Field Engineer reportedly performing calculations to support these contentions. Plant in hot shutdown. Information requested from licensee on restart plans.
1707	Region I called NRC Resident Inspector to discuss open questions.
Approx. 1710	Region I called IE:HQ to discuss open questions.

1720	Region I called licensee. Received licensee commitment to not restart without first providing NRC four hours warning. Discussed open questions with licensee. (1) Was Reactor Vessel wetted? (2) If so, what effect on vessel? (3) What corrective actions prevent reoccurrence? (4) What plans exist for inspection of stainless steel conduits?
Approx. 1830	Opened V.C. airlock for entry.
Approx. 1900	Closed V.C.
---	Chief Operations Engineer recomputed best estimate of water pumped from V.C., to be about 106,000 gallons, which the licensee believed would still not wet reactor vessel.
Approx. 2100	Nuclear side N.P.O. entered V.C. to string hoses for cleaning. Unisolated city water to V.C.
2300+	(1) V.C. sump isolation valve closed. (2) W.H.U.T. still being transferred to Unit 1.

TUESDAY, OCTOBER 21, 1980

PLANT STATUS:	Reactor subcritical in a hot shutdown mode awaiting return to power. The Vapor Containment was closed but unlocked. People working in V.C. City Water had been valved into the Vapor Containment for cleaning.
0100+	Opened V.C. sump isolation valves.
Approx. 0330	Licensee took ten additional swipes of incore instrument conduits, finding 0.065 to 0.605 mg/100 cm^2 of chlorides. Licensee sampled stainless steel wool from the Reactor Vessel insultation; found 0.085 mg chlorides/gram of material.
0430	Nuclear side N.P.O. toured V.C., found elevation 46 feet floor dry, except for low area puddles. V.C. sump full. Maintenance working in reactor vessel cavity.
0440+	Opened V.C. sump isolation valves.
Approx. 0600	O.C.C. informed outage reason changed to chloride cleanup and that unit expected to return on 10/23/80.
0605	NRC IE:HQ Duty Officer called for Plant Status.
Approx. 0800	Sampled V.C. Sump.
0845	Region I called by NRC Resident Inspector; informed of plant status and plans. Immediate Action Letter questions discussed.
Approx. 0900	Started pumping V.C. sump.
Approx. 0930	Spare N.P.O. tagged out the Reactor Vessel Pit Sump Pump controls and fuses. Secured pumping V.C. sump. W.H.U.T. level at 90%.
Approx. 0942	Licensee swiped insulation sleeve for a Reactor Vessel Incore Instrument stub tube; findings 2.9 mg/100 cm^2 of chlorides.
1134	PNO-I-80-154, Containment Fan Cooler Service Water Leak, issued by Region I.
Approx. 1300	Licensee took three swipes in and around insulation sleeve for Reactor Vessel Incore Instrument stub tubes; finding 0.44 to 1.66 mg/100 cm^2 of chlorides.

---	Licensee cleaned incore instrument stainless steel conduits in Reactor Vessel Pit.
Approx. 1430	Opened V.C. sump isolation valves.
1430+	Completed certain precritical checks.
---	Cleared Work Permit on power range N42 detector. Conducted various tests, calibrations and alignments of Nuclear Instrument Channel N42. Inspection of the N42 detector signal and power lead connectors, located in the detector well, found drops of water within the taped connectors. The detector was replaced.
1542	Region I called licensee to solicit commitments per Immediate Action Letter IAL 80-41.
---	Manager, N.P.G. decided to proceed to cold shutdown; thereby, allowing the removal of Reactor Vessel insulation, and the swiping and cleaning of the exposed surfaces.
---	Licensee recognized lacked proof that Reactor Vessel was not wetted.
---	Licensee directed operators to cool Reactor Coolant System (R.C.S.) to cold shutdown.
1659	NRC Resident Inspector entered V.C. for inspection of conditions in Reactor Vessel Pit. Noted overhead lights out, white substance (like salt) on ventilation duct and around seams of Reactor Vessel Mirror Insulation.
2000	Commenced borating Reactor Coolant System to Boron concentration required for cold shutdown.
Approx. 2020	Inserted shutdown Bank A by tripping Reactor.

WEDNESDAY, OCTOBER 22, 1980

PLANT STATUS:	Reactor subcritical and being cooled down to cold shutdown mode. Borating to cold shutdown condition. All control rods inserted into the Reactor. Purging the V.C. W.H.U.T. water being transferred to Unit 1.
Approx. 0045	Maintenance entered V.C. to replace both Reactor Vessel Pit electrical sump pumps.
0530	Blocked Safety Injection.
0615	NRC IE:HQ Duty Officer called to determine Plant Status.
0700+	(1) Still proceeding to cold shutdown. (2) W.H.U.T. being transferred to Unit 1.
Approx. 0845	#21 Residual Heat Removal (R.H.R.) pump in service.
---	IAL 80-41 issued by Region I.
1500	Investigation team dispatched from Region I and other sites.
Approx. 1600	Plant reached Cold Shutdown.
1600	Licensee performed seven swipes of Reactor Vessel shell, mirror insulation and various Reactor Vessel Pit components; finding less than 0.005 mg/100 cm^2 of chlorides. This followed the first opening of the Reactor Vessel Mirror Insulation by the removal of a small square plate located at dead center of the bottom of the Lower Reactor Vessel Head. The swipe results reinforced the licensee's belief that the Reactor Vessel had not been wetted.
1700	Licensee determine boildown residue of 50 mls of Hudson River Water (4620 ppm NaCl) yielded a swipe result of 43.6 mg/100 cm^2 of chlorides.
1900	Investigation team assembled on site and were briefed by Resident Inspectors.
2000	Investigation team conducted first interview.

THURSDAY, OCTOBER 23, 1980

PLANT STATUS:	Reactor now in cold shutdown with multiple activities progressing within the Vapor Containment. The Containment was open.
0000+	Licensee immersed stainless steel plate in river water, dried the plate and swiped it. Sample results showed 1.0 mg/100 cm^2 of chloride.
0430	Licensee swiped five locations on Reactor Vessel surfaces now exposed by removed mirror insulation. Sample results later showed chloride contamination levels of 19.0 to 41.0 mg/100 cm^2. This followed removal of a circular piece of mirror insulation, about two foot in diameter, located dead center on the lower Reactor Vessel head. These results appeared to contradict licensee's belief that the Reactor Vessel was not wetted.
0730	Investigation Team met with licensee to discuss scope and duration of investigation, scope of assignment for each investigator, and current status of plant, licensee's investigation, and plans for return to operations.
0900	Licensee repeated earlier boildown and swipe test of 250 mls of river water. Swipe showed 49.0 mg/100 cm^2 of chlorides.
1000	Licensee performed an investigation team. An analysis of recirculation sump water as requested by the investigation team. Sample showed 3400 ppm NaCl, 30 ppm Boron and 2.8E-3 uc/cc of activity.
1350	Manager, N.P.G. informed investigators that the current estimate of water pumped from the V.C. was 85,000 gallons and that the licensee still believed no water reached the Reactor Vessel.
Approx. 1520	Licensee informed investigation team that they had received report from an S.W.S. that water level may have approached elevation 46 feet grating.
Approx. 1630	Licensee informed investigation team of identities of licensee employees who report to have seen water level within one to four feet of elevation 46 feet grating.

1700 Licensee swiped ten locations in reactor vessel pit. Samples would later show chloride levels from 0.08 to 25 mg/100 cm^2.

FRIDAY, OCTOBER 24, 1980

PLANT STATUS:	Reactor now in cold shutdown with multiple activities progressing within the Vapor Containment. The Containment was open.
0230	Licensee swiped five reactor vessel locations newly exposed on lower hemisphere as insulation was removed. Sample results later show 31 to 170 mg/100 cm^2. This followed removal of the first four pie shaped pieces of mirror insulation on the Lower Reactor Vessel Head.
1020	Licensee called Resident Inspector Office. Informed investigation team that licensee had determined that deposits on Reactor Vessel were definitely residue from evaporated river water.
Approx. 1200	Licensee met with investigation team. Investigation team was informed that the licensee believed about 9 feet of the Reactor Vessel was covered with river water, while in hot shutdown. The status of the plant, licensee's investigation and schedule for corrective actions were discussed.
Approx. 1800	Information Notice 80-07 on the Indian Point 1 incident issued by NRC.

ENCLOSURE 2

OUTSTANDING LICENSEE SUBMITTALS TO NRC

1. Reactor Vessel Stress Analysis Report
2. Reactor Vessel Mirror Insultation Test Report
3. Reactor Trip Cause Identification System Evaluation Report
4. Shift Technical Advisor Performance and Activities Evaluation Report
5. Vapor Containment Dew Point Recorder Trace Evaluation Report
6. Steam Vapor Leakage Detection Systems Capability Report
7. Failure Analysis Program Description
8. Fan Cooler Unit Service Water Containment Isolation Valve Evaluation Report
9. Fan Cooler Unit Cooling Coil and Service Water Pipe Failure Analysis Report
10. Steam Generator Blowdown Line Failure Analysis Report
11. Vapor Containment Sump Pump Failure Analysis Report
12. Reactor Vessel Pit Sump Pump Failure Analysis Report
13. Vapor Containment Survey Evaluation Report
14. Excore Nuclear Instrumentation Evaluation Report
15. Reactor Vessel Paint Chloride Retention Report
16. Recirculation Sump Activity Level Evaluation Report
17. Reactor Vessel Pit Water Transport Path Report
18. Incore Instrument Stub Tube to Reactor Vessel Weld Failure Consequence Report
19. Modification Plans Report
20. Immediate Action Letter No. 80-41 Report